107 Selden Street, Berlin, CT 06037
P.O. Box 270, Hartford, CT 06141-0270

Vincent P. Pace
Assistant General Counsel

January 22, 2024

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051

Re: Docket No. 23-08-09, Annual Electric Distribution Company Reliability and Resilience Framework Review

Dear Mr. Gaudiosi:

Pursuant to section 16-32g of the General Statutes and section 16-32g-1 of the Regulations of Connecticut State Agencies, the Connecticut Light and Power Company d/b/a Eversource Energy (the "Company") hereby submits its 2024 Line Maintenance Plan.

PURA's January 9, 2024 motion ruling in Docket Nos. 22-12-01 and 23-01-32 stated that the Company's "***2024 Line Maintenance Plans should be filed in Docket No. 23-08-09***, 2025 Line Maintenance Plans should be filed in Docket No. 24-08-09, and so forth" (emphasis added). In compliance with that order, the 2024 Line Maintenance Plan is being filed in this docket.

Very truly yours,
Vincent P. Pace
Vincent P. Pace
Assistant General Counsel
On Behalf of CL&P d/b/a Eversource Energy

Attachment: 2024 Line Maintenance Plan

cc: Service list

Docket No. 23-08-09

ELECTRIC UTILITY LINE MAINTENANCE PLAN FILED PURSUANT TO SECTION 16-32g OF THE GENERAL STATUTES OF CONNECTICUT AND SECTION 16-32g-1 OF THE REGULATIONS OF CONNECTICUT STATE AGENCIES

2024 FILING

EVERSOURCE ENERGY

JANUARY 22, 2024

THE EVERSOURCE ENERGY
ELECTRIC UTILITY LINE MAINTENANCE PLAN – 2024

This is the 2024 submission of The Eversource Energy updated Electric Utility Line Maintenance Plan ("Plan"). The Plan has been prepared in accordance with section 16-32g of the General Statutes of Connecticut, section 16-32g-1 of the Regulations of Connecticut State Agencies, and the minimum requirements established by the Public Utilities Regulatory Authority ("Authority"), formerly known as the Department of Public Utility Control ("Department"), by letter dated July 13, 1989.

A) Electric System Description

The Authority's requirements call for a description of the transmission and distribution system, including the miles of plant for both underground and overhead lines, miles of plant by voltage level and miles of plant by type of construction. In accordance with that requirement, Eversource has prepared a table that contains this information, which is attached as Appendix 1. In addition, the following definitions were used in preparing Appendix 1 and other pertinent parts of this Plan:

Covered - Wire - A conductor with an abrasion-resistant outer covering, usually nonmetallic, and intended for use on overhead lines passing near trees.

Non - Covered Wire - Bare wire or any other wire not intended to withstand abrasion to tree contract.

Aerial Cable - A conductor system in which each conductor is covered with a fully insulated covering.

Spacer Cable - A type of electric supply line construction consisting of an assembly of one or more covered conductors, separated from each other and supported from a messenger by insulating spacers.

Underground Cable - Insulated conductors installed in duct or conduit systems.

Direct Buried Cable - Insulated conductors installed in direct contact with earth or in conduit. Primarily used in residential developments and industrial or commercial parks.

- **As directed by the Authority the Plan includes a map of the Eversource service territory, which indicates the location of major electric utility facilities including transmission lines and substations. The map, entitled Transmission System Key Map, is included as part of Appendix 2.** (This map has not yet been updated to include the Company's recently energized new transmission facilities.)

  Also included is a list of the names associated with the alpha-numeric substation designation.

- **Also, as directed, the number of electric distribution customers served by Eversource by customer class as of September 30, 2023, is as follows:**

Response: The number of customers served by customer class as of September 30, 2023, is:

Residential:	1,160,566
Commercial:	107,689
Industrial:	2,853
Public Street Lighting:	5,069
Railroad:	2
Sales for Resale:	30
TOTAL	1,276,209

* This number is lower than that used in interruption reporting statistics due to the fact that financial accounting counts each account as a customer. Interruption analysis requires that each metered location be considered a customer. Some accounts are a summation of several meter locations.

B) Tree Trimming

- **Recent Changes in Vegetation Management Practices Implemented in the Past Two Years**

Post storm cooperation with hard hit towns to address storm damage trees and branches was initiated after Tropical Storm Henri. The effort continues to be employed following impactful storms.

The Enhanced Tree Trimming (ETT) specification was adjusted to be ten feet to the side for branch and tree clearance in 2023 and will continue in 2024.

The Scheduled Maintenance specification for side clearance on backbones will be adjusted to ten feet. Lateral lines will be prioritized to achieve ten feet of side clearance to maximize resources for reliability improvement, with the ultimate goal to achieve ten-foot side clearance on all circuits over time. All lateral lines will have a minimum of eight feet of side clearance. Those changes are reflected in the attached specification in Appendix 3.

- **Description of Line Clearance Organization and Work Force**

Heading into 2024, the Eversource Vegetation Management Program is currently managed by a manager, two Supervisors, twelve Arborists and one billing clerk. Additionally, there are twelve Vendor-Arborists added to assist with tree contractor oversight in the field, and two vendor clerks to assist with processing the tree contractor and municipal police invoices and property owner notification. A diagram of the organization is attached in Appendix 3. The Line Clearance organization structure is to continue in 2024.

All maintenance, capital, emergency, and storm restoration line clearance work will be performed by line clearance contractors.

- **Standards and Specifications for Conductor Clearances and Trimming Frequency**

Eversource schedules maintenance on a 4-year cycle by circuit. Circuits planned for scheduled maintenance are inspected by the Vegetation Management team and trimming is prioritized for greatest reliability impact. A copy of the Eversource Specification for Local Distribution Line Clearance Tree Work and Brush Control is attached in Appendix 3. The specification is an updated version that captures the change in maintenance specification.

- **Service Areas not trimmed within the Normal Trimming Cycle or to the Current Specifications.**

In 2024 all tree work including standard maintenance trimming (“SMT”), backbone maintenance enhanced trimming (“METT-BB”), lateral maintenance enhanced trimming (“METT-LAT”) and lateral enhanced trimming (“ETT”), will be completed in conformance with the specifications shown in Appendix 3, except for locations where denials or modifications to the specifications were made by property owners, per C.G.S 16-234 Section c. (6).

Through November of 2023, 3,044 miles of roadside maintenance and 51 roadside miles of Enhanced Tree Trimming have been completed.

A total of 4,193 roadside distribution miles falls under 2024 scheduled maintenance. Eversource's Vegetation Management team inspects and assesses trees along each circuit and performs tree work to maximize reliability for the greatest number of customers. Customer Focused Enhanced Tree Trimming will be performed on approximately 45 additional miles, which includes removing all branches above and below the conductors that are within ten feet, all trees within ten feet and inspecting and removing hazard and higher risk trees in the fall zone.

Additionally, an Enhanced Tree Removal (ETR) program will include evaluation of risk trees in the fall zone, prioritizing hazard and higher risk trees along the backbones and high customer count laterals that are scheduled for maintenance. Trees failing from outside the clearance zone remain the largest cause of outages and impact to reliability.

Additionally, an Enhanced Tree Removal (ETR) program will include evaluation of risk trees in the fall zone, prioritizing hazard and higher risk trees along the backbones and high customer count laterals that are scheduled for maintenance. Trees failing from outside the clearance zone remain the largest cause of outages and impact to reliability.

- **Information on Tree Trimming Refusals and impact on reliability.**

Eversource will submit all objections (refusals) by 01/31/2024 in accord with the requirements of PURA Docket No. 14-07-18. Objections, modifications and locations where documented notification or consent could not be obtained represents a relatively small number of miles when compared to the total number of miles maintained annually and on the system as a whole. However, in certain locations they can have a significant impact to reliability for both SAIFI & SAIDI. Through November 2023, Eversource has received 1,140 refusals, 4,175 modifications to specification and 811 properties that could not be notified.

- **Required information in annual vegetation management plan**

  In attached Appendix 3, the following information is provided:

  1. Work scope and budget details
  2. Tree and brush work specification
  3. Line clearance organization
  4. Property owner notification and consent procedures
  5. The planned maintenance within each town within the EDC's service territory.

Since the PURA has noted that data "should be filed for a full calendar year", the company intends to file the following additional information no later than January 31, 2024, to meet the requirements of the final decision in PURA Docket No. 14-07-18:

  6. Number of property owner/customer objections by town in prior year.
  7. Number of property owner/customer objections by town in prior year accepted by the Tree Warden.
  8. Number of property owner/customer requests for modifications and decisions reached.
  9. Number of trees per town assessed to be hazardous or non-hazardous.
  10. Number of property owners/customers who give affirmative consent versus non-responses.
  11. Number of mediations conducted and outcome of mediation.

12. Number of objections appealed to PURA by either the EDC or landowner and outcome.
13. Number of removals of non-hazardous trees.
14. Number of RTRP trees planted by the EDC, reasons for planting, costs.
15. Did property owner maintain the newly planted tree?
16. Number of stumps ground by EDC, reasons for stump grinding, cost.

- **Transmission Vegetation Management Program**

The transmission vegetation management program manages trees and other vegetation that may potentially interfere with the operation of the transmission facilities, including substations, structures, and conductors. The Company's intends that transmission corridors are maintained as sustainable, diverse habitat, with grass, shrubs and low-growing trees that can safely coexist with transmission lines. The Routine Maintenance program consists of the following activities:

Scheduled Line Inspections – In compliance with NERC VM Standard, FAC-003, and inspections are performed to identify any problematic vegetation conditions that require corrective action in the upcoming year. All inspections are performed by Company personnel or qualified vendors. All transmission lines are inspected at least once annually. All lines that are subject to FAC-003 requirements are inspected at least twice annually, via ground and aerial patrol.

Cyclical ROW Maintenance – This consists of vegetation control to provide a clear and accessible area for the safe operation, review and maintenance of electric facilities located on the ROW. Reliability will be preserved through the removal of all potentially interfering tree, shrub and vine species that may, through normal growth, encroach within the minimum vegetation clearance distances (MVCD) between the vegetation and the overhead electric conductors, encroach into Minimum Approach Distance (MAD) limiting safe work conditions or impede physical or visual access along the ROW within the cleared and maintained areas of the ROW and is performed on a 4-year cycle. The Company employs Integrated Vegetation Management ("IVM") methods, including the targeted application of herbicides to control tall-growing vegetation that is incompatible based on mature height and selective state-listed invasive woody shrub species within the ROW.

Side Trimming – This consists of the trimming and removal of tree branches that encroach into the ROW from the outside edges of the cleared ROW for the purpose of ensuring adequate clearance between energized conductors and vegetation located outside the maintained corridors. Side Trimming is performed on a 4-year cycle, typically in the same calendar year as ROW maintenance. Clearances are based online voltage and span length (distance from one structure to another), with the minimum clearance distance at the time of cutting being twenty-five feet.

Hazard Tree Removals – Trees along the transmission corridor, both outside and within the easement limits of the ROW are visually inspected to identify those trees that pose a higher risk of falling and causing a disturbance or outage to the transmission system. Those trees are scheduled for corrective action (topping, trimming or removal), with appropriate

notification and/or consent of property owners as required. The inspections are corrective actions are performed in conjunction with the scheduled side trimming.

Transmission Rights of Way Reliability Program for System Resiliency – The program's purpose is the removal of all incompatible species of vegetation within the easement area and fee owned limits of the right of way (ROW), to reduce the risk to the normal operations of the transmission system from trees that fail from outside the maintained ROW. Additionally, the program is to preserve reliability through the removal of all potentially interfering tree, shrub and vine species that may, through normal growth, encroach within the minimum vegetation clearance distances (MVCD) between the vegetation and the overhead electric conductors, encroach into Minimum Approach Distance (MAD) limiting safe work conditions or impede physical or visual access along the ROW. Vegetation species such as native grasses, flowers, ferns and low growing shrubs are considered desirable and shall be preserved whenever possible and encouraged to grow.

In 2016, the Company began its first ROW clearing projects, expanding cleared boundaries of the maintained ROWs. This initiative is planning to continue for all ROW corridors with completion of FAC-003 applicable line ROWs by 2025. In 2024, the Company is planning to clear approximately 3,337 acres, subject to permitting requirements.

C) Maintenance Practices

In accordance with the Authority's requirements, this section of the Plan includes a detailed description of the Company's inspection, testing, and maintenance practices for transmission and distribution lines and equipment, and any significant changes thereto over the past two years.

- **Description of Distribution Maintenance Organization and Work Force**

Electric System Operations

The Electric System Operations organization has the mission to operate the Electric Transmission and Distribution systems. This includes overseeing the scheduling and switching required to both restore power when outages occur, and to safely remove assets from service for maintenance and other construction activities. Electric Systems Operations encompasses first response for outages and trouble events, system-restoration activities and control-room management, and electric system configuration control with the objective of limiting the frequency and duration of customer outages.

Electric Field Operations

The Electric Field Operations organization is responsible for the construction, maintenance and Operations of the CL&P overhead and underground transmission and distribution systems. The Electric Field Operations organization at CL&P is composed of a System Projects group, state-wide program group, and three Division Operations groups, each with responsibility for a specific geographic area.

Engineering

The Engineering organization is structured as a functionalized team with responsibility for all design, engineering and technology functions necessary to perform distribution operations. The Engineering organization includes distribution planning, substation design, protection and controls engineering, telecommunications engineering, distribution engineering, distribution standards and system resiliency. This alignment of engineering functions is designed to promote specialized skills, stream-lined decision-making, and standard distribution-system design.

Station Operations

The Station Operations organization is responsible for the maintenance, construction, and operations of the Connecticut Transmission and Distribution substations. The Substation Operations organization is composed of a 24 x 7 shift electrician response group, a statewide Construction department, and three Division Operations groups, each with responsibility for a specific geographic area.

Field Engineering and Field Communications is responsible for maintenance, troubleshooting, test and commissioning of the Connecticut Transmission and Distribution communications System Data Acquisition and Controls (SCADA), Relay Protection Schemes to include substation and electric field apparatus. The Field Engineering and Field Communications groups are organized as a statewide Field Communication team and two regional Field Engineering teams each with responsibility for a specific geographic area.

Frequency of Inspection and/or Maintenance

As an ongoing activity, Company employees routinely observe the condition of distribution plant. This is done as they travel about the Company's service area to perform field assignments as well as going to and from work. In addition, inspection of the plant goes on as field work is being engineered and as it is physically performed.

Eversource also has a comprehensive inspection, testing, and maintenance program for its distribution facilities. A table of the inspection and maintenance procedures, their frequency, and any frequency changes in the past two years is included as Appendix 4. Appendices 5-20 provide complete procedures and brief outlines of policies pertinent to line inspection and maintenance.

This program has the following among its primary objectives:

- The prevention or mitigation of service interruptions
- Extending the useful life of equipment
- Avoiding future, more costly maintenance, and repairs
- Assuring compliance with:
  - safety rules and regulations
  - Legal requirements
  - contractual agreements

The Eversource Maintenance Program ("EMP") identifies maintenance areas to be addressed by the Distribution Maintenance organization in order to reduce outages, add to the useful life of equipment, and reduce system operating costs.

The following is a brief description of the highlights for major topics regarding the inspection, testing, and maintenance practices for distribution lines and equipment:

1. The following Underground Residential Developments (Formally Direct Buried equipment) is inspected at as required with a max of 15-year intervals:

   Company Owned direct buried facilities including:

   - Pad Mounted Transformers
   - Submersible Transformers
   - Switch Enclosures
   - Switchgear
   - Transclosures
   - Handholes (HH)
   - Risers
   - Fault Indicators
   - Primary and secondary cable

   Refer to EMP 5.11 & 6.11 in Appendix 5 for further details.

2. Capacitor Banks

   All pole top and substation capacitor banks are visually inspected once every year. Substation capacitor banks are routinely inspected monthly. This inspection is intended to determine the condition of the tanks, bushings, terminals, connections, etc. The reactive characteristic of air conditioning load requires a high availability of capacitor banks during summer load periods. The inspection is scheduled for March and repairs are scheduled as problems are identified to ensure repairs are completed by June 1st to prepare for summer loads. An annual infrared survey of capacitor banks is also performed.

   Refer to EMP 5.05 & 6.05 in Appendix 6 for further details.

3. Inspection and Maintenance of pole top Automatic Voltage Regulating Equipment

   Pole top regulators are inspected annually and receive major maintenance as required. All three-phase voltage regulating equipment on circuit backbones receive an annual infrared inspection (Appendix 19).

   Refer to EMP 5.01 & 6.01 in Appendix 8 for further details.

4. Inspection and Maintenance of Reclosers

Line reclosers are inspected as part of the annual infrared inspections, in addition to the site visit for the battery replacement maintenance cycle. Non-SCADA controlled pole top distribution line reclosers are inspected bi-monthly. The vast majority of line reclosers now have microprocessor-based monitoring and are alarmed via the SCADA System. Being SCADA enabled allows alarms to be sent to the SOC providing alerts if issues exist. Alarms received via the SCADA system allow for condition-based inspections. Substation distribution reclosers are visually inspected monthly and the 12Y major for oil filled reclosers.

Refer to EMP 5.44 & 6.44 in Appendix 9 for further details.

5. Inspection and Maintenance – Underground Switches

Underground Switches are inspected on a ten-year frequency.

Refer to EMP 5.51 & 6.51 in Appendix 11 for further details.

6. Inspection and Maintenance – Network Transformers

Network vaults containing network transformers are handled as follows:

A. Maintenance inspection – Energized – Annually
B. Major Maintenance - De-Energized - Every four years

Refer to EMP 5.30 & 6.30 in Appendix 12 for further details.

7. Inspection and Maintenance – Network Protectors

Network Protectors are routinely inspected on an annual basis. All de-energized maintenance is conducted every 2-4 years, depending on the protector type.

Refer to EMP 6.29A, 6.29B, 6.29C & 6.29D in Appendix 13 for further details.

8. Inspection and Maintenance - Underground System - Cable

Street lighting supplied from the underground system is inspected at five-year intervals.

See Underground Vaults & Manholes
Refer to EMP 5.59 & 6.59A & 5.59B in Appendix 17 for further details.
Infrared Inspections in Underground Vaults and Networks are conducted to identify potential problems in primary and secondary cables, network protectors and other underground equipment.

9. Inspection and Maintenance - Street lighting

Street lighting supplied from the underground system is inspected at five-year intervals.

Refer to EMP 5.48, 5.52, 6.52 in Appendix 16 for further details.

10. Infrared Inspection

    The three-phase backbone portions of all circuits are surveyed annually with infrared.

    Refer to EMP 5.22 Appendix 19 for further details.

11. Distribution Wood Pole Inspection and Treatment

    The Company will continue to evaluate the effectiveness of a pole inspection and treatment program along with a capital pole replacement program.

    Refer to EMP 5.61 & 6.61, 6.61A in Appendix 10 for further details.

    All three-phase group operated switches are visually inspected once per year. As required, these switches are operated to check for blade alignment, contact condition, interrupting devices, insulators, arresters, etc. An annual infrared survey of three-phase switches is also performed.

    Refer to EMP 5.15, and 6.15A, 6.15B in Appendix 7 for further details.

12. Three-Phase Group Operated Switches Inspection and Maintenance
    All three-phase group operated switches are visually inspected once per year.

    As required, these switches are operated to check for blade alignment, contact condition, interrupting devices, insulators, arresters, etc. An annual infrared survey of three-phase switches is also performed.

    Refer to EMP 5.15, and 6.15A, 6.15B in Appendix 7 for further details.

13. Inspection and Maintenance of Underground Transformers.

    Radial supplied underground transformers are inspected as required with a max of 10-year intervals.

    Refer to EMP 5.55 & 6.55 in Appendix 15 for further details.

14. Inspection and Maintenance-Underground System - Vaults and Manholes Vaults and manholes are inspected at five-year intervals.

    Refer to EMP 5.59 & 6.59A, 6.59B in Appendix 17 for further details.

15. Inspection and Maintenance-Underground System-Corrosion
    See Underground Vaults & Manholes

    Refer to EMP 5.59 & 6.59A, 6.59B in Appendix 17 for further details.

- **Current Actual Annual Expenditures**

  The 12-month expenditure for maintenance of overhead distribution plant for the period January 1, 2023, through November 30, 2023, was $163.5 million. This equates to $9,801.57 per primary circuit mile when divided by 16,681 overhead primary circuit miles.

- **Completed maintenance.**

  CL&P performs maintenance of its distribution system on a continuing scheduled basis. A copy of the CL&P's Inspection and Maintenance System Report for the period January 1 through November 30, 2023, including a listing of the appropriate staffing levels necessary to complete the 2023 activities outlined in the Plan as follows:

The Connecticut Light and Power Company Inspection and Maintenance System Report									
January 1 Through November 30, 2023									
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 2023**	**Completed by 11/30/2023**	**% completed by 11/30/2023**	**Notes**
1	DB Facilities	Operations	EMP 5.11	Switch/Transformer	72,633	6,328	6,377	101%	1
2	Capacitor Banks	Maintenance	EMP 5.05	Capacitor Bank	1,737	1,737	1,739	100%	4
3	Automatic Voltage Regulators	Maintenance	EMP 5.01	Regulator	850	850	850	100%	4
4	Reclosers	Maintenance	EMP 5.44 - Inspections	Recloser	3,650	913	1,528	167%	2, 3,4
			EMP 5.44 - Major			153	153	100%	3, 4
5	UG System Network Transformers	Maintenance	EMP 5.29, 5.30 - Routine Inspection	Transformer/Protector	620	593 (I)	593	100%	4, 9
			EMP 5.29, 5.30 - Major Maintenance			328 (M)	334	102%	4, 9
6	UG Plant	Operations	EMP 5.59	UG Structure (Manholes & Vaults)	10,792	1,727	1,754	102%	6, 8
7	Subway-Street Lights	Operations	EMP 5.48	Pole	4,016	4,016	4,016	100%	
8	Infrared Inspection	Maintenance	EMP 5.22	Circuit	896	896	896	100%	

NOTES

1 - Number of units to be done in a given year may vary from the quantities called for in the Frequency Table in Appendix #4 of Eversource, d/b/a CL&P Line Maintenance Plan due to anticipated changes to the units of equipment in service at any time due to upgrades, conversions, retirements, and other adjusments.

2 - Non SCADA electronic reclosers are inspected bi-monthly. Hydraulic reclosers are inspected once per year. SCADA enabled electronic reclosers allow for condition based inspections by providing an alarm to the SOC to alert of potential issues

3 - With regard to reclosers, the Company is transitioning from a years-based major maintenance cycle to an operational-based maintenance cycle (i.e. in the future these units will be maintained based upon their number of operations, fault duty, or diagnostic tests rather than once every six years).

4 - This work may be performed by a combination of Company and contractor crews depending on work load and available resources.

5 - In 2008, the Company suspended its annual inspection cycle to eliminate energized oil tests to comply with an interim practice in accordance with a settlement agreement with OSHA.

6 - These values may be adjusted at year-end 2023.

7 - The cumulative staffing levels allocated and necssary for the implementation of these inspection and maintenance programs is equivalent to 72 people working full time, including contractor resources.

8 - Total units inspected include company owned manholes and vaults only.

9- Total Units for networks counts Transformers and Protectors as one. Major Maintenance includes Network Transformers Majors and Protector Majors as separate items.

INDEX OF APPENDICES

Appendix	No./Letter/Section	Title
1		Transmission and Distribution System Miles per Construction Type and Voltage Level
2		Transmission System Maps
3		CL&P Annual Vegetation Management Plan
	Section 1	CL&P Vegetation Management Annual Plan
	Section 2	Specification for Tree Work & Brush Control
	Section 3	CL&P Line Clearance Organization
	Section 4	CL&P Property owner notification and consent procedures.
4		Table of Inspection and Maintenance Frequencies
5	EMP 5.11 6.11	Inspection of Direct-Buried Facilities
6	EMP 5.05 6.05	Capacitor Bank Inspection
7	EMP 5.15 6.15A 6.15B	Pole-Mounted, Three-phase, Group Operated Switches
8	EMP 5.01 6.01	Pole Top Regulators
9	EMP 5.44 6.44	Reclosers and Sectionalizers
10	EMP 5.61 6.61 6.61A	Inspection, Treatment, Restoration and Replacement Guidelines for Distribution System Wood Poles
11	EMP 5.51 6.51	Underground Switches
12	EMP 5.30 6.30	Network Transformers
13	EMP 5.29 & 6.29, 6.29A, 6.29B, 6.29C, & 6.29D	Network Protectors
14	Appendix no longer used.	
15	EMP 5.55, 6.55	Underground Transformers
16	EMP 5.48 & 5.52, 6.52	Street Lighting
17	EMP 5.59, 6.59A, 6.59B	Underground Vaults and Manholes
18	Appendix no longer used.	
19	EMP 5.22	Infrared Survey Program
20	Appendix no longer used.	

APPENDIX 1

TRANSMISSION AND DISTRIBUTION SYSTEM MILES PER CONSTRUCTION TYPE AND VOLTAGE LEVEL

APPENDIX 1

TRANSMISSION AND DISTRIBUTION SYSTEM MILES

PER CONSTRUCTION TYPE AND VOLTAGE CLASS

Transmission			
Construction Type	69 kV Circuit Miles	115 kV Circuit Miles	345 kV Circuit Miles
Overhead Conductor	77	1109	492
Underground Cable	2.8	93.6*	47.3

Distribution				
Construction Type	5 kV Circuit Miles	15 kV Circuit Miles	25 kV Circuit Miles	35 kV Circuit Miles
Covered Wire	413.03	4338.71	2951.87	62.95
Aerial Cable	1.83	113.58	44.14	46.80
Spacer Cable	25.61	310.54	176.64	32.50
Other Overhead	1991.82	3604.28	2433.62	132.59
Underground**	77.51	3575.84	3138.98	67.97

* This includes three cable circuits 5.8 miles long operating at 138 kV across Long Island Sound to the New York State line that is owned by CL&P. The remaining length is owned by the Long Island Power Authority.

** Includes both Direct Buried and Conventional Duct-Type Circuit Miles.

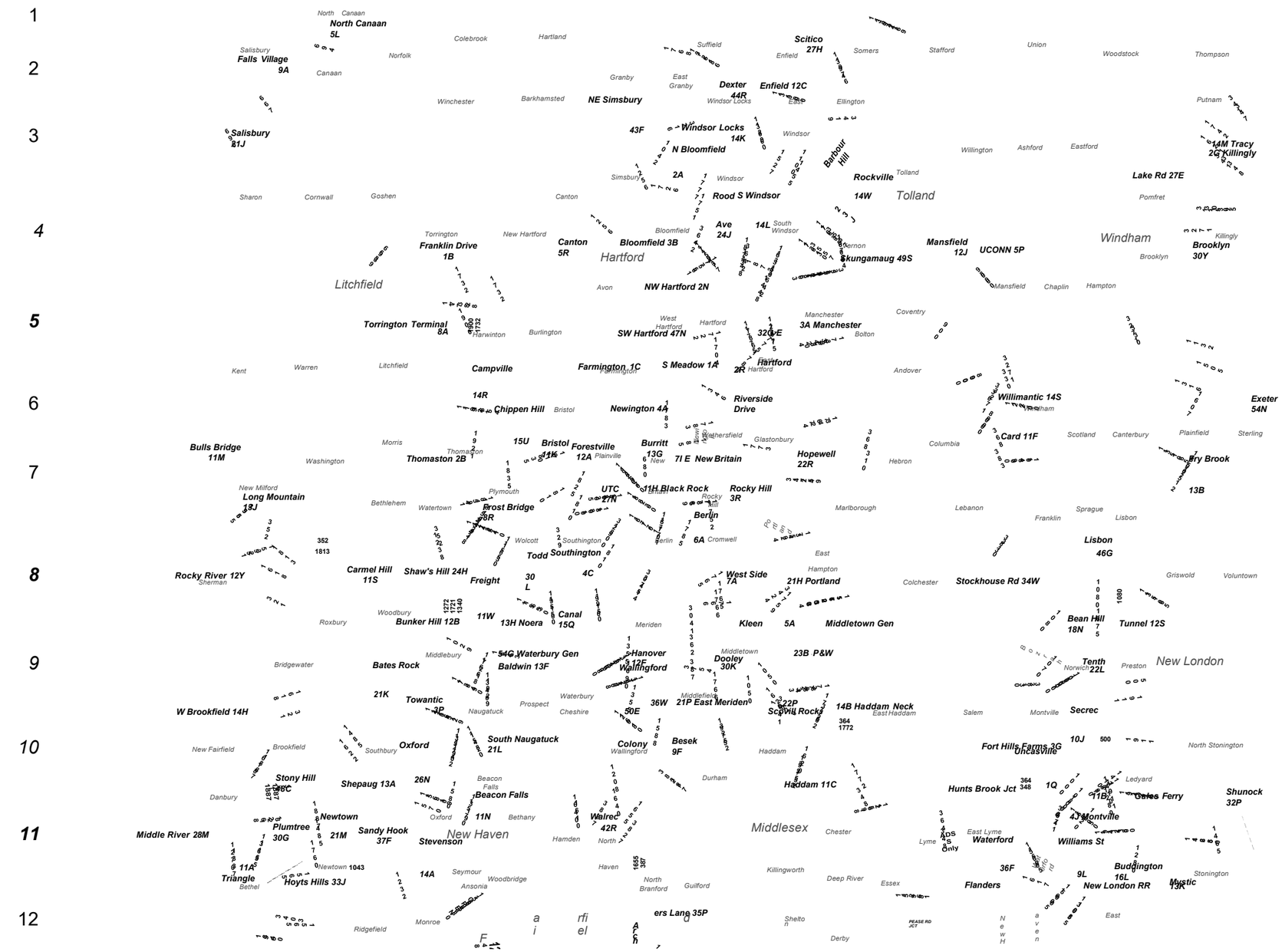
APPENDIX 2

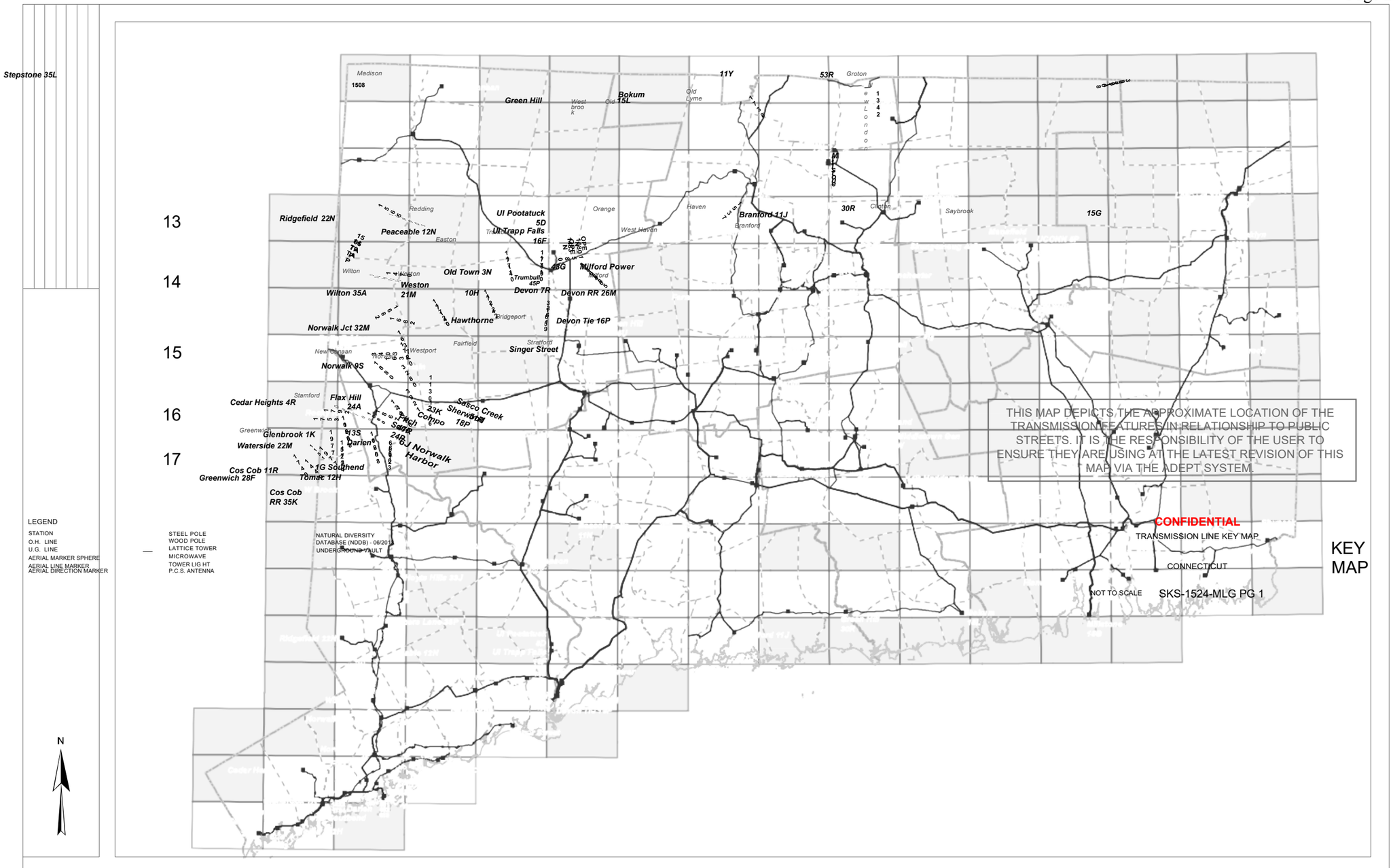
TRANSMISSION SYSTEM MAPS

REV.0-INITIAL DOCUMENT CONTROL DATE 04/09

ES SITING AND PERMITTING DEPARTMENT MUST BE CONTACTED IF ANY WORK IS PERFORMED WITHIN THE NDDB AREAS SHOWN.

STRUCTURE NUMBERS SHOWN MAY BE INCORRECT DUE TO RENUMBERING. FIELD VERIFICATION MAY BE NECESSARY.


A
B
C
D
E
F
G
H
J
K
L
M
N
O
P
Q
1
2
3
4
5
6
7
8
9
10
11
12
North Canaan
5L
Falls Village
9A
Salisbury
81J
Sharon
Cornwall
Goshen
Litchfield
Franklin Drive
1B
Torrington Terminal
8A
Kent
Warren
Campville
14R
Bulls Bridge
11M
Thomaston 2B
Morris
Washington
Long Mountain
19J
New Milford
Rocky River 12Y
Sherman
Carmel Hill
11S
Shaw's Hill 24H
Bunker Hill 12B
Roxbury
Bates Rock
21K
Towantic
3P
W Brookfield 14H
Oxford
Stony Hill
Shepaug 13A
Newtown
Plumtree
30G
Middle River 28M
Triangle
Hoyts Hills 33J
Ridgefield
Colebrook
Norfolk
Winchester
Barkhamsted
Torrington
New Hartford
Canton
5R
Canton
Avon
NW Hartford 2N
Burlington
Harwinton
Bristol
Chippen Hill
15U
Bristol
Forestville
12A
Plainville
Plymouth
Bethlehem
Watertown
Frost Bridge
5R
Wolcott
Southington
Todd
Freight
30
L
Canal
15Q
13H Noera
Meriden
Middlebury
54G Waterbury Gen
Baldwin 13F
Naugatuck
Prospect
Waterbury
Cheshire
Southbury
Beacon Falls
Beacon Falls
Oxford
11N
Bethany
Seymour
Woodbridge
Ansonia
Monroe
Hartland
Granby
Barkhamsted
NE Simsbury
43F
Windsor Locks
14K
N Bloomfield
2A
Simsbury
Windsor
Rood S Windsor
Bloomfield
Bloomfield 3B
Hartford
Ave
24J
14L
South Windsor
Suffield
East Granby
Windsor Locks
Dexter
44R
Enfield 12C
East
Windsor
Barbour Hill
Scitico
27H
Enfield
Somers
Ellington
Rockville
14W
Tolland
Tolland
Kernon
Skungamaug 49S
Mansfield
12J
UCONN 5P
Mansfield
Chaplin
Hampton
Stafford
Union
Woodstock
Thompson
Putnam
14M Tracy
2G Killingly
Willington
Ashford
Eastford
Lake Rd 27E
Pomfret
Windham
Killingly
Brooklyn
30Y
Brooklyn
Coventry
Manchester
3A Manchester
Bolton
West Hartford
Hartford
320 E
SW Hartford 47N
S Meadow 1A
2R
Hartford
Farmington 1C
Farmington
Middlesex
Chester
Deep River
Essex
Killingworth
Shelton
Derby
Andover
Hebron
Columbia
Marlborough
Lebanon
Colchester
Hopewell
22R
7I E New Britain
Burritt
13G
New Britain
11H Black Rock
UTC
27N
Berlin
Rocky Hill
3R
Berlin
6A
Cromwell
Middletown
23B P&W
Dooley
30K
Wallingford
Colony
Wallingford
Besec
9F
Durham
Haddam
Haddam 11C
East Haddam
Scovill Rocks
14B Haddam Neck
Middlefield
21P East Meriden
36W
50E
Hampton
West Side
7A
21H Portland
Kleen
5A
Middletown Gen
Riverside Drive
Newington 4A
Wethersfield
Glastonbury
Willimantic 14S
Windham
Exeter
54N
Card 11F
Scotland
Canterbury
Plainfield
Sterling
Fry Brook
13B
Lisbon
46G
Franklin
Sprague
Lisbon
Stockhouse Rd 34W
Griswold
Voluntown
Bean Hill
18N
Tunnel 12S
Tenth
22L
Preston
New London
Norwich
Montville
Secrec
Salem
Fort Hills Farms 3G
Uncasville
10J
500
North Stonington
Hunts Brook Jct
1Q
11B
Ledyard
Gales Ferry
Shunock
32P
Montville
Williams St
Waterford
East Lyme
Lyme
Old Lyme
Buddington
16L
New London RR
Flanders
36F
9L
Mystic
15R
Stonington
East
Newtown 1043
Newtown
Sandy Hook
37F
Stevenson
New Haven
Hamden
North Haven
North Branford
Guilford
Walnut
42R
Walnut
Hartford
2R
Hartford
Hartford
Hartford


Stepstone 35L
13
14
15
16
17
Madison
1508
Green Hill
Bokum
15L
11Y
53R
Groton
Ridgefield 22N
Redding
Peaceable 12N
Easton
Ul Pootatuck
5D
Ul Trapp Falls
16F
Orange
Haven
West Haven
Branford 11J
Branford
30R
Clinton
Saybrook
15G
Wilton
Weston
Old Town 3N
Trumbull
45P
Milford Power
Milford
Wilton 35A
Weston
21M
10H
Devon 7R
Devon RR 26M
Hawthorne
Bridgeport
Devon Tie 16P
Norwalk Jct 32M
Fairfield
Stratford
Singer Street
New Canaan
Westport
Norwalk 9S
Stamford
Cedar Heights 4R
Flax Hill
24A
Sasco Creek
Sherwood
18P
23K
Compo
Greenwich
Glenbrook 1K
Waterside 22M
13S
Darien
24R
6J Norwalk
Harbor
Cos Cob 11R
Greenwich 28F
1G Southend
Tomac 12H
Cos Cob
RR 35K
LEGEND
STATION
O.H. LINE
U.G. LINE
AERIAL MARKER SPHERE
AERIAL LINE MARKER
AERIAL DIRECTION MARKER
STEEL POLE
WOOD POLE
LATTICE TOWER
MICROWAVE
TOWER LIG HT
P.C.S. ANTENNA
NATURAL DIVERSITY
DATABASE (NDDB) - 06/2013
UNDERGROUND VAULT
N
THIS MAP DEPICTS THE APPROXIMATE LOCATION OF THE TRANSMISSION FEATURES IN RELATIONSHIP TO PUBLIC STREETS. IT IS THE RESPONSIBILITY OF THE USER TO ENSURE THEY ARE USING AT THE LATEST REVISION OF THIS MAP VIA THE ADEPT SYSTEM.
CONFIDENTIAL
TRANSMISSION LINE KEY MAP
CONNECTICUT
NOT TO SCALE
SKS-1524-MLG PG 1
KEY
MAP

EVERSOURCE

SUBSTATION	PAGE
A	
AfJAWAfA 16C	WMA
ALTRESCO 41A	(ALTRESCO)
Afl.HERST 17K	WMA
ANSONIA 6K	(UICO)
ARCHERS LANE 35P	WMA
ASH CREEK 7C	(UICO)
ASHFla.D 38A	WMA
B	
BALDWIN 13F	9-F
BARBOUR HILL 23J	4-K
BATES ROCK 21K	9-A
BEACON FALIS 11N	10-F
BEAN HILL 1BN	(CITY OF NORWICH)
BERKSHIRE 1BC	WMA
BERKSHIRE POWER 31G	(BERKSHIRE POWER)
BERLIN 6A	7-J
BESECK 9F	13-H
BLACK ROCK 11H	7-H
BLANDFORO 19J	WMA
BLOOMFIELD 38	4-J
BOKUM 15L	12-L
BRANFORD 11J	13-H
BRANFORD RAIL.ROAD 48R	(Afl.TRAK)
BRECKWOOD 20A	WMA
BRIDGEPORT ENERGY 48G	(UICO)
BRISTOL 11K	7-G
BROOKLYN JOY	4-P
BUCK POND 348	(WG&E)
BUDDINGTON 16L	(CITY OF GROTON)
BUUS BRIDGE 11M	7-C
BUNKER HILL 128	8-F
BURRITT 13G	(FRPCO)
C	
CABOT 19G	WMA
CAfAPVILLE 14R	6-F
CANAL 15Q	4-G
CANTON 5R	4-G
CARD 11F	6-N
CARMEL HILL 11S	8-E
CDEC 51L	(CDECCA)
CEDAR HEIGHTS 4R	16-B
CHICOPEE 1BL	WMA
CHIPPEN HILL 15U	7-G
CLINTON 21S	WMA
COBBLE MOUNTAIN 18F	WMA
COLONY SOE	(WALLINGFORD ELECTRIC DMSION)
COMPO 23K	16-D
COS COB 11R	17-8
COS COB RAIL.ROAD 35K	(CT DOT)
CUMBERLAND 228	WMA
D	
DARIEN 13S	16-C
DEVON 7R	WMA
DEVON RAIL ROAD 26M	(CT DOT)
DEVON TIE 16P	(UICO)
DEXTER 44R	(DEXTER)
OOOLEY 30K	9-J
DOREEN 19A	WMA
DUDLEY 21A	(CITY OF NORWICH)
E	
EAST DEVON 7R	WMA
EAST HARTFORD 32G	5-K
EAST MERIDEN 21P	9-J
EAST NEW BRITAIN 7L	7-H
EAST SHORE 9G	(UICO)
EAST SPRINGFla.D 5J	WMA
ELM 22G	(WG&E)
ELY AVENUE	WMA
ENFla.D 12C	3-K
EXETER 54N	(OXFORD ENERGY CO.)

SUBSTATION	PAGE
F	
FAIRMONT 16H	WMA
FALIS VILLAGE 9A	2-D
FARMINGTON 1C	6-H
FIVE CORNERS	(N.G.)
FLANDERS 11Y	12-N
FLAX HILL 24A	15-C
FORESTVILLE 12A	7-G
FORT HILL FARMS 3G	WMA
FRANCONIA 22H	WMA
FRANKLIN DRIVE 18	5-F
FREIGHT 11W	9-F
FRENCH KING 218	WMA
FROST BRIDGE BR	WMA
FRY BROOK 138	7-P
G	
GALES FERRY 11B	11-0
GENERAL ELECTRIC 14E	WMA
G. E. TEST 38G	WMA
GLENBROOK 1K	17-8
GREEN HILL 30R	12-K
GREENWICH 28F	17-A
GUNN 15A	WMA
H	
HIADDAfA 11C	10-L
HIADDAfA NECK 148	10-L
HIALVARSSON CONVERTER STATION 14P	WMA
HANOVER 12F	9-H
HAWTHORNE 10H	(UICO)
HOLYOKE 17L	(HG&E)
HOPEWELL 22R	7-K
HOTY'S HILL 33J	WMA
I	
INDIAN WELL 47P	(UICO)
INGLESIDE 52W	(HG&E)
J	
JUNE STREET 1P	(UICO)
K	
KIWNGLY 2G	3-P
L	
LAKE ROAD 27E	4-P
LISBON 46G	(CITY OF NORWICH)
LONG MOUNTAIN 13J	WMA
LUDLOW 19S	WMA
M	
MANCHESTER 3A	5-K
MANSFla.D 12J	4-M
MIDDLE RIVER 28M	11-8
MIDDLETOWN 5A	0-K
MIDWAY 198	WMA
MILFORD POWER 43G	14-F
MILLSTONE 15G	12-N
MIX AVENUE 32K	(UICO)
MONSANTO 50G	WMA
MONTAGUE 21C	WMA
MONTVILLE 4J	11-0
MOUNT TOM 22C	WMA
MYSTIC 13K	12-P
N	
NEW LONDON RAIL.ROAD 53R	12-0
NEWINGTON 4A	6-H
NEWTOWN 12M	11-D
NOERA 13H	WMA
NORTH 398	(UHV)
NORTH BLOOMFIELD 2A	3-H
NORTH CANAAN 5L	1-D
NORTH HAVEN 10A	(UICO)
NORTH WALLINGFORD 36W	(WALL ELEC. DMSION)
NORTHEAST SIMSBURY 43F	3-H
NORTHFIELD MOUNTAIN 16R	WMA
NORTHPORT	(LILCO)
NORTHWEST HARTFORD 2N	5-J
NORWALK 9S	15-C
NORWALK HARBOR 6J	16-C
NORWALK JCT. 32M	15-C
O	
OLD TOWN 3N	(UICO)
ORCHARD 27A	WMA
OSWALD 308	WMA
OXFORD 26N	10-E

SUBSTATION	PAGE
P	
PARTRIDGE 15E	WMA
PARTRIDGE JCT.	WMA
PEACEABLE 12N	13-C
PEQUONNOCK BJ	(UICO)
PIERCE 55W	(WALL. ELECTRIC DMSION)
PINESHED 23F	WMA
PIPER 21N	WMA
PLAINFIELD 1BK	WMA
PLEASANT 168	WMA
PLUMTREE 30G	11-C
POCHASSIC 37R	WMA
PODICK 18G	WMA
PORTLAND 21H	8-K
PRATT & WHITNEY 238	9-K
PROSPECT 248	WMA
R	
RIDGEFla.D 22N	13-C
RIVERSIDE DRIVE 2R	6-J
ROBERTSVILLE 16K	WMA
ROCKVILLE 14W	4-L
ROCKY HILL 3R	7-J
ROCKY RIVER 12Y	8-C
ROOD AVE 24J	4-J
S	
SAI.JSBURY 21J	3-C
SANDY HOOK 37F	11-E
SASCO CREEK 51R	(CT DOT)
scmco 21H	2-K
SCOVILL ROCK 22P	9-K
SECREC 10J	(SOUTHEASTERN CT. RESOURCE RECOVERY FACIUIY)
SHAWINIGAN 55E	WMA
SHAWS HILL 24H	8-F
SHELBURNE 29R	WMA
SHEPAUG 13A	10-E
SHUNOCK 32P	11-0
SILVER 30A	WMA
SILVER LAKE 5C	WMA
SINGER 34C	(UICO)
SKUNGAfAAUG 49S	5-M
SOUTH N,AWAfl. 42E	WMA
SOUTH END 1G	17-B
SOUTH MEADOW 1A	6-J
SOUTH NAUGATUCK 21L	10-F
SOUTH WINDSOR 14L	4-K
SOUTHINGTON 4C	8-G
SOUTHWEST HARTFORD 47N	5-J
SOUTHWICK 29A	WMA
STEPSTONE 35L	12-J
STEVENSON 14A	11-E
STOCKHOUSE ROAD 34W	(BOZRAH L&P CO)
STONY BROOK 548	WMA
STONY HILL 48C	11-C
T	
TENTH 22L	(CITY OF NORWICH)
THAMES 39R	WMA
THOMASTON 28	7-F
TODD 30L	8-G
TOMAC 12H	17-8
TORRINGTON TERMINAL 8A	5-8
TRACY 14M	3-P
TRAP FALIS 16F	(UICO)
TRIANGLE 11A	11-C
TRUMBULL 45P	(UICO)
TUNNEL 12S	9-0
U	
UCONN 5P	5-M
UNCASVILLE 1Q	10-0
W	
WALLINGFORD 13M	(WALL ELECTRIC DMSION)
WALLINGFORD ENERGY 6G	(WALL ELECTRIC DMSION)
WAL.REC 42R	10-H
WATERBURY GENERATION 54G	9-F
WATERSIDE 22M	17-8
WEST BROOKFla.D 14H	10-C
WEST SIDE 7A	8-J
WEST SPRINGFIELD BC	WMA
WESTON 21M	14-D
WILLIAMS 9L	12-L
WIWMANTIC 14S	6-N
WILTON 35A	14-C
WINDSOR LOCKS 14K	3-J
WOODLAND 17G	WMA

345kV
115kV
69kV

@MOBILE XFMR CONNECTION
@GENERATING CAPACITY

EVERSOURCE ENERGY

SYSTEM DIAGRAM INDEX

BY	REV. NO.	DATE	SIZE	DWG. NO.
MLG		01/05/24	B	SKS-1524-MLG PG 1

APPENDIX 3

CL&P ANNUAL VEGETATION MANAGEMENT PLAN

Eversource Vegetation Management 2024

EXPENSE PROGRAMS	Note	Budget	Backbone Miles	Lateral Miles
Roadside Maintenance*	1	$29,850,000	1,249	2,944
Reclaim Backbone	2	$0		
ROW Brush Control* (Cir. Miles)	3	$900,000	96	
ROW Side Pruning	4	$125,000		
Vine Control	5	$220,000		
Traffic Control	6	$0		
Customer Request Work	7	$750,000		
Mid-Cycle	8	$0		
Emergency Restoration	9	$2,000,000		
Transformer Enclosure	10	$10,000		
Other	11	$245,000		
EXPENSE SUMMARY		**$34,100,000**	**1,345**	**2,944**

CAPITAL PROGRAMS		Budget	Backbone Miles	Lateral Miles
Customer Focus ETT*	12	$5,500,000		45
DOT Project	13	$3,000,000		
Tree Removals	14	$18,000,000		
Reliability Removals	15	$14,800,000		
CAPITAL SUMMARY		**$41,300,000**		**45**

	TOTAL	Budget	Backbone Miles	Lateral Miles
* Included in Cycle		**$75,400,000**	1,345	2,989
% of Total System Miles (Approx)		25.6%		
Total System Miles	16,950			

NOTES

1 Roadside Maintenance includes assessment of scheduled miles, Standard Maintenance Trimming (SMT) on prioritized laterals, Backbone Enhanced Tree Trimmed, Lateral Maintenance Trimming (LMETT) on laterals previously Enhanced Tree Trimmed
2 Re-establishing ETT clearance where on backbones where new trees have grown in or over the wire zone (Retired)
3 Brush removal and treatment in right-of-ways (ROW). Work performed on 4-year cycle
4 Performed on ROWs scheduled for brush removal and involves the pruning of trees growing into the ROW from the side
5 Performed on laterals 2 years after they have been cleared by scheduled maintenance, and 1 year on backbones. Vines growing on poles o
6 Town or State mandated traffic control during scheduled work - included in unit price of maintenance
7 Inspection and completion of customer requested work and reliability issues
8 Performed on circuit backbones 2 years after maintenance
9 Expense for tree crews during restorations not associated with major storms
10 Vegetation control performed on 2-year cycle within customer owned transformer enclosures
11 Efficiency Incentive / Other
12 Performed on laterals experiencing emerging reliability issues
13 Cooperative effort with CT DOT for tree work along state roadways
14 Removal of risk & hazard trees along Roadside Maintenance
15 Focused removals on poor performing devices

Town	Maintenance on Backbone	Scheduled Maintenance on Laterals	Total Mileage Assessed
ANDOVER	0.37	2.01	2.38
ASHFORD	0.00	6.39	6.39
AVON	11.39	23.20	34.59
BARKHAMSTED	6.84	12.38	19.21
BEACON FALLS	4.42	5.38	9.79
BERLIN	17.90	12.50	30.40
BETHANY	4.39	20.46	24.85
BETHEL	10.17	17.07	27.24
BETHLEHEM	0.00	2.23	2.23
BLOOMFIELD	0.07	8.06	8.13
BOLTON	2.12	8.05	10.17
BRANFORD	9.11	19.36	28.47
BRISTOL	20.49	23.40	43.90
BROOKFIELD	25.88	39.60	65.48
BROOKLYN	5.35	18.18	23.53
BURLINGTON	0.00	0.09	0.09
CANTERBURY	0.00	1.50	1.50
CANTON	21.38	31.90	53.28
CHAPLIN	5.30	34.60	39.90
CHESHIRE	5.00	13.05	18.05
COLCHESTER	4.47	25.28	29.74
COLEBROOK	4.46	0.03	4.49
COLUMBIA	9.38	30.95	40.34
CORNWALL	0.00	5.98	5.98
COVENTRY	4.50	21.02	25.52
CROMWELL	3.91	3.90	7.80
DANBURY	26.66	28.61	55.27
DARIEN	6.07	21.82	27.89
DURHAM	8.97	19.75	28.72
EAST GRANBY	13.42	21.52	34.94
EAST HADDAM	2.39	8.92	11.31
EAST HAMPTON	18.64	53.10	71.73
EAST HARTFORD	15.79	40.79	56.57
EAST LYME	2.83	13.83	16.66
EAST WINDSOR	4.11	14.15	18.26
EASTFORD	0.00	1.99	1.99
EASTON	0.00	0.05	0.05
ELLINGTON	5.62	11.31	16.93
ENFIELD	32.71	55.02	87.73
ESSEX	3.88	6.34	10.21
FAIRFIELD	0.47	1.95	2.42

Town	Maintenance on Backbone	Scheduled Maintenance on Laterals	Total Mileage Assessed
FARMINGTON	11.78	9.47	21.25
GLASTONBURY	35.26	64.57	99.83
GOSHEN	3.31	18.53	21.84
GRANBY	1.74	9.20	10.94
GREENWICH	23.36	46.99	70.35
GRISWOLD	3.03	7.52	10.55
GUILFORD	5.86	10.17	16.03
HADDAM	1.69	12.57	14.27
HAMPTON	0.92	0.00	0.92
HARTFORD	3.36	16.77	20.13
HARTLAND	0.06	18.27	18.33
HARWINTON	0.00	3.91	3.91
HEBRON	4.31	25.21	29.52
KENT	0.22	9.49	9.71
KILLINGLY	0.32	0.99	1.31
LEBANON	2.81	14.38	17.19
LEDYARD	4.24	27.96	32.19
LISBON	7.59	39.50	47.09
LITCHFIELD	10.92	32.51	43.43
MADISON	0.03	0.00	0.03
MANCHESTER	19.92	44.69	64.61
MANSFIELD	10.11	29.95	40.06
MARLBOROUGH	6.05	19.00	25.05
MERIDEN	19.11	39.59	58.70
MIDDLEBURY	9.00	45.66	54.66
MIDDLEFIELD	0.33	0.18	0.51
MIDDLETOWN	29.44	44.80	74.24
MONROE	1.26	2.76	4.02
MONTVILLE	21.97	41.91	63.89
MORRIS	2.16	11.25	13.41
NAUGATUCK	7.26	12.27	19.53
NEW BRITAIN	11.18	21.84	33.03
NEW CANAAN	20.85	38.30	59.15
NEW HARTFORD	15.79	45.78	61.56
NEW LONDON	12.74	14.14	26.88
NEW MILFORD	32.50	84.36	116.86
NEWINGTON	6.70	9.04	15.74
NEWTOWN	37.70	75.93	113.63
NORTH BRANFORD	0.00	0.09	0.09
NORTH CANAAN	5.96	10.01	15.96
NORTH STONINGTON	6.73	43.00	49.73

Town	Maintenance on Backbone	Scheduled Maintenance on Laterals	Total Mileage Assessed
NORWALK	27.54	52.44	79.99
OLD SAYBROOK	1.44	2.02	3.46
OXFORD	13.80	20.60	34.40
PLAINFIELD	4.81	22.44	27.24
PLAINVILLE	9.99	15.95	25.93
PLYMOUTH	2.92	5.92	8.84
PORTLAND	8.65	29.64	38.29
PRESTON	0.00	0.02	0.02
PROSPECT	4.67	18.37	23.04
PUTNAM	5.55	21.20	26.74
REDDING	1.23	1.82	3.05
RIDGEFIELD	0.00	0.04	0.04
ROCKY HILL	5.23	8.04	13.26
ROXBURY	0.00	4.79	4.79
SALISBURY	11.01	44.46	55.48
SEYMOUR	3.25	7.94	11.19
SIMSBURY	14.54	35.81	50.35
SOUTH WINDSOR	14.00	15.36	29.37
SOUTHBURY	14.13	45.52	59.65
SOUTHINGTON	13.68	24.34	38.01
SPRAGUE	0.17	1.80	1.97
STAFFORD	0.70	0.91	1.61
STAMFORD	37.79	59.13	96.92
SUFFIELD	7.13	5.61	12.74
THOMASTON	4.40	3.64	8.04
THOMPSON	11.00	40.87	51.87
TOLLAND	6.52	27.76	34.28
TORRINGTON	39.53	92.95	132.48
VERNON	6.57	8.23	14.80
VOLUNTOWN	0.00	0.18	0.18
WARREN	4.24	6.04	10.28
WASHINGTON	19.18	61.75	80.93
WATERBURY	38.28	63.92	102.20
WATERFORD	11.09	27.33	38.42
WATERTOWN	9.74	25.70	35.43
WEST HARTFORD	22.07	55.64	77.71
WESTBROOK	2.81	11.66	14.47
WESTON	0.85	4.54	5.39
WESTPORT	33.60	86.49	120.09
WETHERSFIELD	11.86	23.96	35.82
WILLINGTON	16.19	42.59	58.78

Town	Maintenance on Backbone	Scheduled Maintenance on Laterals	Total Mileage Assessed
WILTON	6.27	35.89	42.15
WINCHESTER	12.29	31.50	43.79
WINDHAM	10.42	15.62	26.05
WINDSOR	8.64	9.79	18.43
WINDSOR LOCKS	14.56	23.99	38.56
WOLCOTT	16.22	29.49	45.70
WOODBURY	24.58	82.00	106.58
WOODSTOCK	0.00	0.07	0.07
Total	**1,249**	**2,944**	**4,193**



SPECIFICATION FOR LOCAL DISTRIBUTION LINE CLEARANCE TREE WORK AND BRUSH CONTROL

Revision 2023

Table of Contents

Section **Page Number**

General Requirements 1
Scope of Work 2
Scheduled Maintenance Trimming 2
Enhanced Tree Trimming 4
Maintenance Enhanced Tree Trimming 5
New Business and Capital Construction 6
Tree Removal 6
Stumps 7
Brush and Vine Removal 7
Wood and Chip Disposal 8
Substation Perimeter Clearing 9
Definitions 10

2023

Sean Redding, Manager - CT Vegetation Management
Stan Bartkowiak, Supervisor - CT Vegetation Management
Kathy Ferrier, Supervisor - CT Vegetation Management
Doug Pistawka, Supervisor - CT Vegetation Management
Jenna Turner, Supervisor - CT Vegetation Management

Eversource
Specification for Local Distribution
Tree Work and Brush Control

1. General Requirements

This document describes the scope of work and technical requirements for the Eversource Distribution Line Clearance Program. All work shall be performed by qualified line clearance Contractors. Safety shall take precedence over all requirements described herein and at no time shall work be performed in an unsafe manner.

- All contact with the public and government officials shall be done in a courteous manner.

- Work shall always be subject to inspection by Eversource and government officials. The crew foreman, or the Contractor's designee, shall notify Eversource of each crew's daily work location and of any change made during the day.

- Work shall be performed in such a manner that it will not interfere with or affect in any way the operation of any existing energized lines or electrical equipment, except as specifically directed by Eversource.

- All line clearance work shall be performed in strict accordance with all applicable federal, state, and local governmental laws and regulations or approved standards and safety practices – ANSI A300 (Part 1), Best Management Practices – Utility Pruning of Trees, ANSI Z133.1, OSHA 29 CFR 1910.269. The Contractor shall be responsible for the knowledge, supervision, and enforcement of them.

- Each crew will have in the vehicle the Eversource Image Summit forms and door hangers. Administration of the process will be in accordance with all Eversource Image Summit procedures and guidelines.

- When necessary, the Contractor requests permission from tree owners and others to perform line clearance tree work around electrical conductors. When the tree owner is not at home, use the appropriate permission card and customer brochure. For all refusals, light trims, or no contacts the Contractor shall fill out a copy of the DISTRIBUTION LINE CLEARANCE MODIFICATION FORM and submit the form weekly or approved electronic form.

- The crew foreman shall complete and submit weekly company approved reporting forms, adding information daily for all T&M work. Paper forms of this report shall be submitted to Eversource no later than Tuesday of the week following the completed work week. Electronic forms shall be submitted at least weekly.

- The line clearance crew shall work progressively along the distribution system starting at the substation, or as directed by Eversource, and shall complete all work on a given

portion of the line before starting work at another location, unless otherwise approved by Eversource.

- Re-trimming will be required to correct all situations where trimming quality is determined by Eversource to be improper.

- Climbing irons shall not be used in any tree unless the tree is to be removed.

- Wherever Eversource is solely responsible for clean-up on scheduled work, clean-up shall be completed daily, and the site shall be left in at least as neat and orderly condition as it was found.

- All planned work must be set up following the Eversource CT Vegetation Management Work Planning Guide (**EXHIBIT G**).

2. Scope of Work

This Specification covers the trimming and removal of trees and brush, including the use of herbicides for brush control along overhead electrical lines and around substations owned or used by Eversource. This includes clearing for existing lines, as well as for new lines, and applies to local distribution only (along and off-roads) and not bulk supply distribution rights-of-way. Each tree must be evaluated on its own at the time it is trimmed. The tree crew must consider the variables including tree species, condition, growth rate and location.

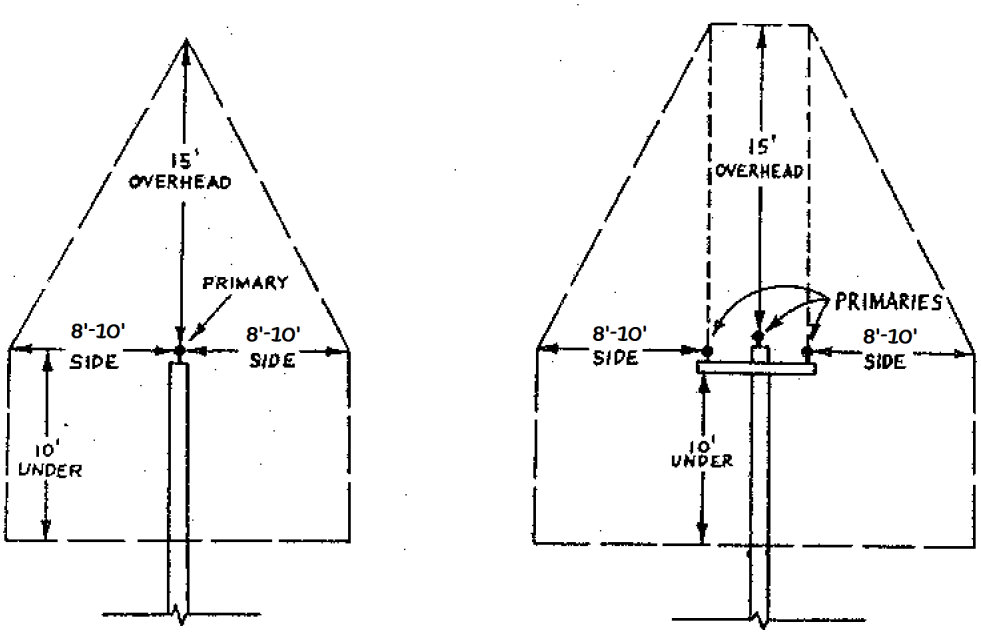
2.1. Scheduled Maintenance Trimming (SMT)

2.1.1. Primary Conductors

Conductor clearances relative to various primary wire positions are shown in Figure 1. Remove all branches within the clearance zone bounded by the dashed line perimeter and all overhead hazards within reach of a 70-foot aerial lift.

Figure 1

CLEARANCE ZONE DIMENSIONS
For
PRIMARY VOLTAGE CONDUCTORS (2.4 to 34.5 kV)



2.1.1.1. Overhead Clearances
15-feet overhead clearance shall be measured vertically upward from the highest primary.

2.1.1.2. Side Clearances
8-feet side clearance shall be measured horizontally outward from the outermost primaries, 10-feet on prioritized laterals.

2.1.1.3. Under Clearances
10-feet under clearance shall be measured vertically downward from the lowest primary.

2.1.1.4. Brush and Vine Clearances
Selectively remove only that tree brush which is presently at least 16-feet tall within the clearance zone or growing into the clearance zone. All vines which are growing up poles or guy wires shall be cut at ground level and cleared 6-feet up the pole or guy.

2.1.1.5. Water Sprouts and suckers

Water Sprouts and suckers shall not be trimmed; they shall be removed.

2.1.2. Secondaries Without Primaries Above and Service Drops

2.1.2.1. Triplex

Do not trim around them unless authorized by Eversource. When approved, trim only limbs in contact with the conductor. Trimmed branches shall provide 2-feet of clearance around conductors.

2.1.2.2. Open Wire Secondary (OWS)

Contractor shall trim all OWS conductors. Trimmed branches shall provide 2-feet of clearance around conductors.

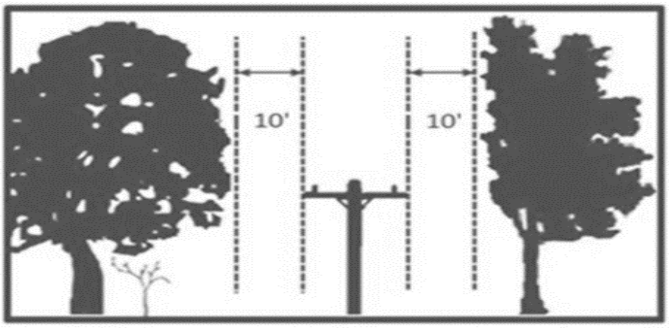
2.2. Enhanced Tree Work (ETT)

2.2.1. Primary Conductors

Conductor clearances relative to various primary wire positions are shown in Figure 2. Remove all branches and tall growing trees within the clearance zone bounded by the dashed line.

Figure 2

Clearance Zone Dimensions for Enhanced Tree Work



2.2.1.1. Overhead Clearances

Prune and remove all limbs in the clearance zone over the outermost primary.

2.2.1.2. Side Clearances

10-feet side clearance shall be measured horizontally outward from the outermost primaries.

2.2.1.3. Under Clearances
Prune and remove all limbs in the clearance zone under the outermost primary.

2.2.1.4. Brush and Vine Clearances
Remove all brush that is capable of growing tall enough to touch the primary conductors that are in or growing into the clearance zone. All vines which are growing up poles or guy wires shall be cut at the ground line and cleared 6-feet up the pole or guy.

2.2.1.5. Water Sprouts and Suckers
Water sprouts and suckers shall not be trimmed; they shall be removed.

2.2.2. Arboricultural Tree Management
Remove trees if foliage removal from obtaining clearance exceeds ANSI A300 pruning standard.

2.2.3. Fall Zone Hazard Tree Management
Inspect, evaluate, and eliminate all hazardous trees within the fall zone by pruning or removal. Utility compatible species may remain.

2.3. Maintenance Enhanced Tree Trimming on Backbones or Laterals (METT) and Laterals (METTL)

2.3.1. Primary Conductors on METT

2.3.1.1. Overhead Clearances
Re-clear to the previously established ETT clearances including new growth into the clearance zone. Remove all overhead hazards within reach of a 70-foot aerial lift.

2.3.1.2. Side Clearances

2.3.1.2.1. Laterals - 8-feet side clearance shall be measured horizontally outward from the outermost primaries, 10-feet on prioritized laterals.

2.3.1.2.2. Backbones - 10-feet side clearance shall be measured horizontally outward from the outermost primaries.

2.3.1.3. Under Clearances
Prune and remove all limbs in the clearance zone under the outermost primary.

2.3.1.4. Brush and Vine Clearances
Remove all brush that is capable of growing tall enough to touch the primary conductors that are in or growing into the

clearance zone. All vines which are growing up poles or guy wires shall be cut at the ground line and cleared 6-feet up the pole or guy.

2.3.1.5. Water Sprouts and suckers

Water sprouts and suckers shall not be trimmed; they shall be removed.

2.3.2. Primary Conductors on METTL (Originally Cleared Between 2004 and 2011)

2.3.2.1. Overhead Clearances

Trim to provide a minimum of 20-feet of overhead clearance and remove all overhead hazards within reach of a standard 70-foot lift unit.

2.3.2.2. Side Clearances

2.3.1.2.1. Laterals - 8-feet side clearance shall be measured horizontally outward from the outermost primaries, 10-feet on prioritized laterals.

2.3.2.3. Under Clearances

Prune and remove all limbs in the clearance zone under the outermost primary.

2.3.2.4. Brush and Vine Clearances

Remove all brush that is capable of growing tall enough to touch the primary conductors that are in or growing into the clearance zone. All vines which are growing up poles or guy wires shall be cut at the ground line and cleared 6-feet up the pole or guy.

2.3.2.5. Water Sprouts and Suckers

Water sprouts and suckers shall not be trimmed; they shall be removed.

2.4. Hazard Tree Management

Remove all hazard trees up to and including 16-inches DBH within 10-feet of the outermost conductor. The removal of any tree greater than 16-inches DBH must be approved by Eversource. Eversource will provide specific instructions in each case depending upon whether others are sharing the cost or disposing of the tree parts. Hazard Tree Management applies to 2.1 (SMT) and 2.3 (METT/METTL) specifications.

2.5. New Business and Capital Construction

Prune all branches and remove all tall growing tree species per Enhanced Tree Trimming (ETT) specification 2.2.

3. Tree Removal

- Contractor shall not "top" trees unless authorized by the Owner's Representative. Normally, these trees will be removed.

- Remove any tree which would, after trimming to clearance, exceed the ANSI A300 foliage removal standard. Trees greater than 16-inches DBH shall be removed only after authorization from Eversource.

- Specific instructions on billing of removals, depending upon whether others are sharing the cost will be provided by the Owner's Representative.

4. Stumps

All stumps shall be cut as close to the ground as possible, and in no case shall they be cut higher than 3-inches unless used as supports for a fence or approved otherwise by Eversource. All stumps shall be cut off parallel to the ground to avoid leaving sharp points on the stumps.

In Connecticut, stumps capable of resprouting (all hardwoods, pitch pine, and vines) shall be treated with an Eversource approved herbicide mixture in accordance with label directions and regulatory requirements.

5. Brush and Vine Removal

5.1. Brush

Brush shall not be trimmed or topped. The width of the brush removal area shall be 10-feet on each side of the outermost conductor or growing into that zone. Flat cutting or selective brush removal shall be approved by Eversource.

Cutting of tree brush and vines shall be done with care to minimize damage to non-interfering shrubs, such as the following that are permitted to remain:

Pinxterbloom Azalea	Hazelnut
Highbush Blueberry	Gray Dogwood
Redosier Dogwood	Huckleberry
Oldfield Common Juniper	Spicebush
Sweetfern	Mountain Laurel
Bayberry	Rhododendron

5.2. Vines

All vines that are growing up poles or guy wires shall be cut at ground level, cleared for 6-feet up the pole or guy, and treated with an Eversource approved herbicide mixture in accordance with label directions and regulatory requirements.

All vines that are growing into the clearance zone from an abutting tree or structure shall be cut at the ground level, trimmed away from primary conductors, and treated with an Eversource approved herbicide mixture in accordance with label directions and regulatory requirements.

6. Wood and Chip Disposal

The Contractor shall make every effort to minimize the amount of wood and wood chip disposal that requires hauling away from the site. This can be accomplished by; making agreements with property owners to leave logs and larger limbs at the site for use as firewood, blowing chips onto the ground in rural and unimproved natural locations with approval, and offering chips to property owners for use as mulch. All debris shall be disposed in accordance with all local laws and regulations.

The Contractor shall not leave wood debris that can be chipped overnight except on off-road sections.

6.1. Chips

Smaller limbs, branches, or cut-off brush shall be chipped, normally by chipping into a truck mounted dumping chip box. However, at unimproved natural locations, chips may be blown upon the ground provided that the depth of fresh chips shall be no greater than 3-inches. Limited brush piling may be done along the edges of off-the-road pole lines, either method being subject to the landowner's approval.

6.2. Logs

Logs from the tree trunks and larger limbs shall be cut into mutually agreed or convenient handling lengths. No logs shall be split.

6.3. Debris disposal

The tree owner shall be given first preference to utilize logs and/or chips. This agreement shall be made at the time the work is scheduled.

6.3.1. Chips

Where chips cannot be left on site, they shall be delivered to the nearest appropriate disposal space.

6.3.2. Logs

Logs shall be left at the work site in a safe location, not to pose a hazard to anyone, for a maximum of 7 days, during which time they will be available for pick up. Any logs remaining after 7 days shall be delivered to the appropriate disposal site.

7. Substation Perimeter Clearing

This section describes how tree and brush work shall be performed around substations. Prior to beginning any work around a substation, Eversource personnel will provide site specific guidelines to the Contractor. At no time shall Contractor personnel enter the fenced area of the substation without an Eversource approved escort and personal protective equipment (i.e. Fire Resistant clothing).

7.1. Brush removal

7.1.1. Non-visually sensitive or non-landscaped substations

Cut and remove all brush within 10-feet of the substation fence. If the land adjacent to the substation fence slopes toward the fence, the cleared area shall be 20-feet.

7.1.2. Visually sensitive or landscaped substations

Clear as far away from the fence as practical as directed by the Eversource representative.

7.2. Pruning

Trim back all branches to a minimum of 10-feet from the fence.

7.3. Ornamental Screens

Ornamental trees and shrubs (arborvitae, yew, etc.) that have been planted to provide a visual screen of the substation shall not be removed. If necessary, shearing shall be performed as directed by the Eversource representative.

7.4. Stump treatment

All stumps from trees and brush that have been removed and are capable of re-sprouting shall be herbicide treated with an appropriate herbicide as directed by the Eversource representative.

7.5. Cleanup

Remove and dispose of all trimmings and removal debris away from the job site unless directed otherwise by Eversource. The site shall be left in at least as neat and orderly condition as it was found.

8. Definitions

ANSI A300 (Part 1) Pruning – American National Standard for Tree Care Operations – Tree Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning).

ANSI Z133.1 – American National Standard for Arboricultural Operations – Safety Requirements.

Backbone – A section of line starting at a substation and extending to the first fused device or single/double phase reclosing device.

Brush - Tree species with a DBH of less than 6-inches, that can grow tall enough to reach conductors. Occasionally, shrub species are considered as brush, if they must be removed for line clearance or access.

Clearance - The distance between vegetation and conductor.

Contractor - The business or employees of that business, that has contracted with Eversource to perform line clearing.

Diameter Breast Height (DBH) - Diameter of a tree measured at 4.5-feet above ground level, perpendicular to the axis, on the uphill side of the tree. Where a DBH falls between two 0.1-inch increments, the measurement shall be rounded down to the last 0.1 inch. Special DBH Situations: (1) The DBH shall be measured above any stem bulge, branch whorl, or other deformity that would inflate DBH. (2) On codominant trees, the DBH shall be measured as one tree if the fork occurs above 4.5-feet and as multiple trees if the fork occurs below 4.5-feet. If the fork occurs exactly at 4.5-feet, the DBH will be measured just below the fork and beneath any swelling that would inflate DBH (USDA Forest Service; National Urban Forest Inventory and Analysis Field Guide Version 9.1, 2021).

Fall Zone - The area including the roadside clearance zone and extending from the conductors out a distance to where an uprooted tree could strike the conductor and cause an outage.

Hazard tree – Any tree or part of a tree that is (1) dead, (2) extensively decayed, or (3) structurally weak, which, if it falls, would endanger utility infrastructure, facilities, or equipment.

Lateral – A section of primary voltage line extending from the end of backbone to a secondary or service wire.

Line Clearing – Controlling vegetation to maintain proper clearance from conductors which includes tree trimming, removal, and brush and vine removal.

METT– Maintenance Enhanced Tree Trimming on Backbone or Laterals.

METTL – Maintenance Enhanced Tree Trimming on Laterals.

Modification – When the property owner requests modification to required clearances.

OSHA – Occupational Safety and Health Administration.

Overhead hazards – Dead, dying, diseased, insect infected and structurally weak branches including those which could break at weak points and strike conductors.

Refusal – When a property owner does not allow any tree work to be performed.

Risk Tree – The combination of; the likelihood of a tree-wire conflict or tree failure occurring, and the severity of the potential consequences including but not limited to injury, utility infrastructure damage or electric service disruption.

Shrub - A woody plant normally maturing less than 20-feet in height and presenting a generally bushy appearance because of its several erect, spreading, or prostrate stems.

Stump Treatment - Herbicide applications made to stumps capable of resprouting (all hardwoods and Pitch Pine) to prevent the stump from sprouting.

Substation - An electrical facility that receives electricity at high voltages and reduces the voltage so that it can be passed on to customers at a lower voltage.

Tree - A woody plant normally maturing at 20-feet or more in height, usually with a single trunk, unbranched for several feet above ground, with a definite crown.

Wires/Lines/Conductors - the overhead wires which carry the electric current at required voltages. Also to be considered for tree clearance and safety are other pole mounted equipment such as transformers, fuses, circuit breakers, etc.

Wire types –

Primary - A wire running from pole to pole operating at a voltage level exceeding 600 volts (2,400 to 34,500 volts on the Eversource overhead System), and normally located at the top of a pole.

Secondary - A wire running from pole to pole operating at a voltage level of 600 volts or less (normally 120 to 240 volts on the Eversource overhead System), and generally located approximately 4-feet below the primary.

Triplex - Two insulated wires in a twisted configuration around a bare neutral wire.

Open Wire Secondary - Three parallel wires normally in a vertical configuration separated from each other by a few inches.

Service Drop - The secondary wires connecting the point of attachment on the premises being served to the nearest pole of the distribution system.

Eversource Vegetation Management Work Planning Guide

Work Planning

General Description

This guide describes the process for Eversource and its Contractor to plan scheduled work, including providing notification and obtaining consent per Section 16-234 of the Connecticut General Statutes as amended by Public Act No. 14-151 and as ordered in the final decision issued by the Public Utilities Regulatory Authority ("PURA") on June 25, 2014 in Docket No. 12-01-10. In addition, the guide identifies the responsibilities and expectations for the Work Planner.

Contractor Representative of Eversource

The Work Planner is performing as a contractor representative of Eversource and shall at all time:

- Maintain a neat, clean and professional appearance.
- Be trained in and exhibit strong interpersonal and customer-focused communications skills.
- Be knowledgeable about all aspects of utility arboriculture including:
    - Eversource's tree work specifications; and
    - Federal, state and local laws and regulations.

Planner Expectations

The contractor shall ensure that property owners or abutting property owners understand the extent of the proposed tree work to be performed and shall make every effort to obtain full consent to prune and remove trees and brush and cut vines in compliance with state statutes, regulatory requirements, Eversource's specifications and local or state permits. Objections, refusals, modified specifications and failure to contact customers shall be considered exceptions to normal practice and will be properly documented. However, the Work Planner shall not attempt to obtain permission in a manner that is threatening, intimidating or may appear to be threatening or intimidating to a tree owner.

Planning

Municipal Communication

Prior to work planning beginning, Eversource or its representative will communicate with the Town and Tree Warden the scheduled work including location of work, work type, and specifications.

Eversource and the town will discuss opportunities to coordinate efforts for shared work, parking locations and debris disposal.

All local ordinances will be evaluated and applicability determined.

Eversource will request the necessary permit from the town for pruning trees in the public right of way.

Property Owner Identification

Property owner information shall be obtained from municipal tax assessor's lists.

Information will be used to identify parcel information, property owners, and mailing address.

Starting and Ending Points

Typically, a starting point would be the beginning of a road or the source of the circuit (i.e. substation) and the ending point would be the end of the road or circuit. It may be appropriate to change the starting point to meet requirements of municipal officials or for reliability improvements.

Survey and Evaluation

Planned Work Survey

The contractor shall survey the entire circuit as part of the bid preparation. Based on the planned work type, each tree shall be evaluated to determine properties needing work and the specific tree work to be performed at least 10 days prior to notification and consent. The work to be proposed is as required per the specifications outlined in Eversource's *Specification for Local Distribution Line Clearance Tree Work and Brush Control* 2014-A Revision and Section II – Special Conditions and Amendments of the contract.

Compatible trees and shrubs listed in the State Vegetation Management Task Force Report under the Right Tree, Right Place section or that may be added by DEEP in the future, shall remain unless special circumstances exist that warrant pruning or removal.

Property and Tree Evaluation

At locations the contractor has determined work is required, the Work Planner will evaluate all vegetation that could affect the electrical facilities now and in the future based on the planned work type.

The Work Planner shall take into consideration individually each tree's species, condition (vigor, disease, defects, and structure), growth rate, failure characteristics and location (proximity, soil type, and slope) in determining scope of work to be performed.

Additionally, per the National Electric Safety Code (NESC), movement of vegetation during typical weather conditions plus sag of conductors due to elevated temperatures or icing must be considered when determining the extent of tree work to be performed.

The Work Planner most consider when proposing pruning the final structure, look and risk of the tree. The specific pruning required and final form of the tree must be relayed to the property owner and consideration of removal of the tree as an option must be made if any aspect of the tree may be compromised or unfavorable.

Public Right-of-Way and Private Property

The Work Planner determines whether the tree or part of the tree that requires work is on or overhanging the Public Right-of-Way or on Private Property

Tree work that is on or overhanging the Public Right-of-Way will require notification to the abutting property owner.

Tree work that is on private property will require consent of the property owner.

Property Owner Identification

Based on the information available from tax assessor's records, the Work Planner must determine if the property owner resides at the property where the work is to be performed or not.

If the property owner resides at the property where the work is to be performed, the Work Planner will follow the steps for in- person contact. If the property owner does not reside at the property where the work is to be performed, the Work Planner will follow the steps to contact by certified mail.

Notification and Consent Procedure

Property owner resides at property of tree work:

In Person Contact

The Work Planner shall:

- Identify themselves as a contractor working as a representative of Eversource.

- Provide the property owner with informational brochure.
- Explain their purpose for being there and summarize the goals of Eversource's line clearance program (i.e. visual and physical access to electric facilities; prevention of equipment damage; provide reliable electric service).
- Explain the tree work specification (SMT, ETT, or Hazard Tree Removal) and specifically the proposed tree work for that location.
- Explain that the owner's signature of consent for work on private property and initials for verification of notification is required before any tree work can be performed and ask that they sign the completely filled- out Eversource Proposed Tree Work form.
- Record the tree owner's name and address on the Eversource Status Record form and indicate explicitly the planned work and the level of consent received or notification verified from the property owner.

Property Owner is Not Present

The Work Planner Specialist shall:

- Leave the Eversource Tree Work door hanger with the informational brochure describing the work, the contractor's contact name and phone number, and the filled out Eversource Proposed Tree Work form.
- Return to the location the next day or as soon as possible to determine if the door hanger has been acknowledged and returned to the door with Proposed Tree Work form signed for consent and initialed for notification.
- Answer any questions received from the property owner from the contact phone number provided.
- Record the status and date of the owner's consent and notification on the Eversource Status Record form, if door hanger has been returned.

Door Hanger Not Returned

The Work Planner shall:

- Leave a second door hanger and repeat steps defined above.
- Obtain the telephone number from customer service, municipal or internet records and attempt to contact owner by phone at different times of the day to obtain consent and document notification.
- If the tree owner cannot be contacted, compete the Tree Work Modification form and update the Status Record form as a "No Contact".

- Follow steps for sending a certified letter stated below.

Property owner does not reside at property of tree work

Certified Letter

The Work Planner shall:

- Provide Eversource with information on
  - Property requiring tree work
  - Property Owner's Name and Address
  - Proposed Tree Work Form filled out for property
- Eversource will send the property owner via certified mail with return receipt:
  - A cover letter explaining purpose of mailing with instructions
  - Informational brochure
  - Proposed Tree Work Form
  - Self-addressed stamped envelope to return the signed consent form if needed.
- Eversource will notify contractor of return receipts for notification and returned, completed Proposed Tree Work forms

Modifications of Specifications

All modification to the specifications of proposed work must be documented and reported to PURA. Modifications can include:

- Trimming less then proposed (Modification)
- Denied consent of work on private property (Denial)
- Objection to proposed work in the Public Right-of-Way (Objection)
- Response to attempts to obtain consent unanswered (No Contact)
- Failure to notify (No Notification)

Private property tree work

Where the Work Planner cannot obtain full consent for pruning or removing trees and brush on private property, they shall provide Eversource with a copy of the Tree Work Modification form.

Eversource will evaluate the tree conditions, their impact on the electric system and determine the next course of action.

Eversource may:

- Contact the tree owner in person, by phone or letter to discuss options
- File the refusal for future reference.

Public Right-of-Way tree work

Where the Work Planner receives an objection to pruning or removing trees and brushes on or overhanging the Public Right-of-Way, they shall provide Eversource with a copy of the Tree Work Modification form.

Eversource will evaluate the tree conditions, their impact on the electric system and determine the next course of action.

Eversource may:

- Contact the tree owner in person, by phone or letter to discuss options
- Refer the objection to the municipal or state authority that has jurisdiction over trees in the public way. The Town Tree Warden or State Commissioner of the DOT then must make a decision within 10 business days.
- Based on the decision, Eversource or the abutting property owner may appeal the decision to PURA within ten business days.
    - PURA will schedule a mediation session within thirty calendar days
    - If property owner refuses mediation, PURA will hold a hearing within sixty days of the appeal
    - If mediation session is held and no resolution is reached, PURA will hold a hearing within thirty calendar days of the mediation session.

Objection, Mediation, or Hearing decision

Final decisions after appropriate time periods will be relayed to the contractor to proceed with work as determined in such final decisions. Status Record forms will be updated to indicate approved work.

Records Processing

Eversource Status Record

Specific information of proposed tree work at each property, status of consent and notification and all pertinent information shall be recorded on the Status Record form. The detail includes exactly how and what is to be trimmed and removed and if necessary, any modification to the specifications. The date of consent and notification will also be recorded for record.

Transfer of Information

When all the consent and notification for the circuit has been completed:

- Review the Eversource Status Record for completeness and ensure information will be clear to the tree crew.
- Provide one copy of the Eversource Status Record to EVERSOURCE and the Contractor General Foreman or the assigned tree crew.
- Provide verbal, on-site instructions to the assigned tree crew for unusual or complicated requests.

Record Keeping

Eversource and the contractor will retain copies of all completed Proposed Tree Work forms, Status Record forms and Tree Work Modification forms for twenty-four months from received date.

Eversource will keep a log of all the properties and property owner notification or consent that was attempted, the initial status received from the customer, any objections referred to the Tree Warden or DOT, their decisions, any appeals to PURA of those decisions, outcome of mediation or hearings.

Town and DOT Permits

Eversource or the contractor is required to obtain permits for planned work on town roads or state roadways.

A permit from the Town Tree Warden is required to prune trees on or overhanging the town road Public Right-of-Way.

A written permit is required from the Town Tree Warden to remove a tree in the town road Public Right-of-Way

Proceeding with Work

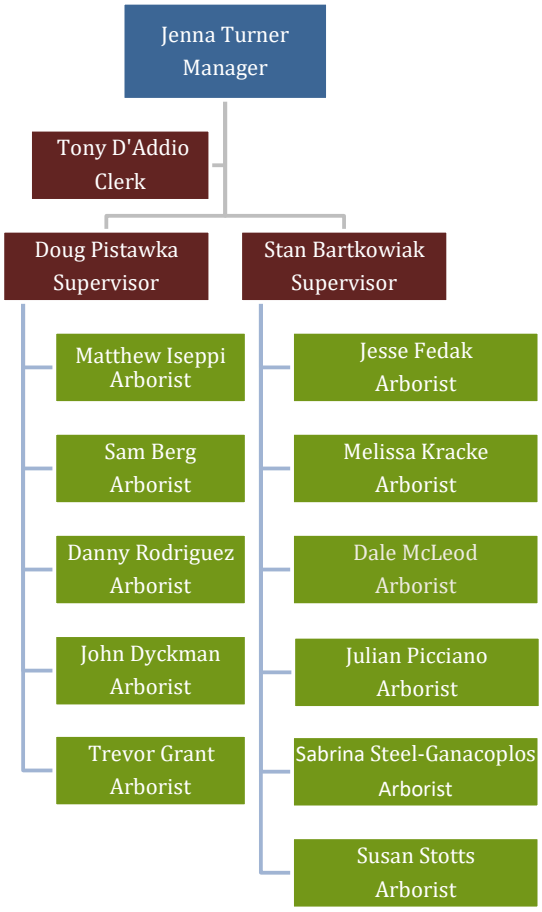
The contractor may begin work as planned with consent for private trees, after fifteen business days of documented notification of trees on or over the Public Right-of-Way, and when all permits have been obtained.

Documentation

The following shall be used to document the permission process:

- Proposed Tree Work form
- Status Record form
- Tree Work Modification Form
- Letters to customers
- Return Receipt cards

Eversource CT Vegetation Management Organization



APPENDIX 4

TABLE OF INSPECTION AND MAINTENANCE FREQUENCIES

Ref. No.	Types of Equipment/Procedure	Frequency Now	Frequency Prior	Remarks
1.	Direct Buried (DB) Facilities	15	No Change	
2.	Capacitor Bank			
	Pole Top	1Year	No Change	
	Substation	Monthly		
3.	Inspect & Maintain Pole-top Voltage Regulating Equipment	1 Year	No Change	
4.	Inspect, Test, and Maintain Reclosers			
	SCADA Controlled	Annually	No Change	Being SCADA enabled allows alarms to be sent to the SOC providing alerts if issues exist. Alarms received via the SCADA system allow for condition-based maintenance.
	Non-SCADA Controlled	Bi-Monthly	No Change	
	Substation	Monthly		
				Additional equipment checks are performed following storms and line faults.
	Major Maintenance			
	Oil	12 Year	No Change	Scheduled Major Maintenance for oil filled Reclosers may be deferred, if a capital replacement project has been formally established and is being implemented on a 12-year replacement plan
5.	Network Transformers	Annually	No Change	Routine Maintenance Inspection
	Protectors	2 or 4 Years	No Change	Major Maintenance/Frequency dependant on model # of protector
6.	Underground Plant	5 Year	No Change	
7..	Streetlights in Underground Areas	5 Years	No Change	Metal streetlight poles are inspected at a 6-year interval.
8.	Infrared Inspection	Annually	No Change	3-phase circuit backbone and associated pole mounted reclosers, Sectionalizers, 3-phase regulators, capacitors, and switches.
9.	Distribution Wood Pole Insp. & Treat.	15 Year	No Change	
10.	Disconnect Switches (3-Phase Group Operated Switches)	Visual – 1M Infrared – 6M Motor Control Visual 3 Year	Major Maintenance as required with 1 Year Visual on Backbone	Motor Control Visual Inspection coincides with the Battery Inspection and Replacement.

Ref. No.	Type of Equipment/Procedure	Frequency Now	Frequency Prior	Remarks
11.	Underground Transformers	10 Years	5 years	The ten-year inspection of the underground transformer, performed energized, has been changed from the previous five-year cycle to better coincide with other underground equipment maintenance.
12.	Vaults & Manholes	5 Years	No Change	This inspection should be performed coincident with equipment maintenance frequencies.

APPENDIX 5

DIRECT BURIED FACILITIES

5.11 Underground Residential Developments

1.1 General Description

This procedure defines the schedule, inspection, and the reporting requirements for the inspection of Direct Buried facilities. Periodic inspections of Direct Buried and associated equipment at the specified interval allows preventative and corrective actions to be performed prior to situations becoming hazardous to the public or resulting in equipment failure. Inspection and failure recording ensures that corrective actions are taken by appropriate departments.

See EMP instruction 6.11 for details on performing the DB Inspection

NOTE: All specific maintenance requirements that are followed by a triangle symbol "▲" are explained in the Maintenance Basis Documentation section of this chapter.

1.2 Facilities/Equipment

Company-owned direct-buried facilities including:

- Pad-Mounted Transformers
- Switch Enclosures
- Switchgear
- Transclosures
- Handholes (HH)
- Pull Holes
- Risers
- Fault Indicators ▲
- Primary and secondary cable

1.3 This document applies URD equipment only and the equipment defined above are covered by other EMPs when not part of an URD.

2.0 Reference Documents

TD 861	Reporting Distribution Equipment Failures and Defects
TD 804	Inspection of Underground Residential Developments
EMP 5.33	Overhead Circuits
EMP 6.11	Underground Residential Developments Inspection
WMS 82.03	Excavating Around Energized Pad Mounted Equipment and

DTR	Underground Residential Developments Underground Lines Sections 42, 43 and 44
DTR 04.225	Minimum Vertical Clearance Between Conductors on the Same Pole – Based on NESC Rules 230 and 235
FIST 016	Facilities Instructions, Standards, and Techniques - Volume 4-1A (7-2020)
EL-5036-V2	Power Plant Electrical Reference Series, Volume 2: Power Transformers

3.0 Definitions

3.1.1 **Y**=Year, i.e. 2Y= 2 Years

3.1.2 **A/R**= As Required

4.0 Inspection and Maintenance Activity Schedules

4.1 Inspection and/or maintenance intervals for equipment are listed in Table 1

Table 1 – Underground Residential Developments Maintenance Intervals

Underground Residential Developments Maintenance Schedule	Interval
Time-Directed	
Routine Inspection (CT)	15Y
Replace Fault Indicators	(Note 1)
Condition-Based	
Any defects found during **Routine Inspection**	A/R (Note 2)

NOTE: 1. Replacement will occur 20 years after the manufacturer's battery life expectancy which is stamped on the Fault Indicators.

2. Repair or replace any defective components found during the Routine Inspection if possible or note repairs that cannot be completed during the Routine Inspection for future correction.

5.0 Maintenance Categories

Table 2 – Underground Residential Developments Maintenance Schedule by Type

Type	Inspection Type	Energized / De-Energized
Time-Directed	Routine Inspections	Energized
	Replacing Fault Indicators	Energized
Condition-Based	Defective Component Repairs	De-Energized

6.0 Failure Findings

6.1 Failures of devices shall be documented in the failure reporting system used by your region and appropriate for the asset class.

6.1.1 Distribution equipment failures shall be reported using EFRS. See TD 861 for additional information.

6.1.2 Distribution asset failures shall be documented using Maximo.

6.1.3 Stations asset failures shall be documented using CASCADE.

6.2 Minor deficiencies (e.g., premature paint peeling on newer equipment, or misaligned doors on pad-mounted equipment) should also be reported to Distribution Standards.

6.3 Analysis of URD equipment failures should be performed when deemed necessary by Distribution Standards

7.0 Underground Residential Developments Maintenance Basis Documentation

Table 3 – Underground Residential Developments Maintenance Basis Documentation

Requirement	Basis
Fault Indicator Replacement – 20Y	Manufacturer's recommendation of a 15- to 20-year battery life.
Routine Inspection – 15Y	Company history has shown that the 10Y interval has been successful in keeping the equipment reliable. • A review of data from the Equipment Failure Reporting System (EFRS) indicates a very low failure rate for pad-mounted transformers. Although EFRS data indicates a higher failure rate for DB cable, few interruptions can be eliminated by routine preventative maintenance practices. • The EFRS has shown a very low failure rate for other DB related equipment such as handholes, secondary cables, etc.
	The US Department of the Interior Bureau of Reclamation document, Facilities Instructions, Standards, and Techniques, recommends a 3-5 inspection interval for transformers.
	The EPRI Power Plant Electrical Reference Series, Volume 2, Power Transformers, states "Every transformer should be inspected at regular intervals. The length of those intervals varies from company to company, depending on prior experience, severity of service, and harshness of the environment.

6.11 – Direct Buried Inspection

DIRECT - BURIED INSPECTION

NUMM 6.11 – Rev. 4

WORK REQUEST NO	MAP NO.	LOCATION .

ITEM NO.	Inspection Item	DETAILS
01	DETERIORATION/PROPER GRADING	Inspect the vault, extensions, concrete slab/pad, and hand-holes for deterioration and proper grading and ensure they are properly set.
02	PROPERLY SET	Check the transformer / enclosure to verify they are properly set on the concrete pad or slab.
03	CONDITION OF CASE	Inspect the condition of the case. Check it for internal and external rust, dents, etc.
05	STANDARD SIGNS AND LABELS*	Ensure standard signs, cable tags, and labels (internal and external) are in place and in good condition as specified in DTR Sections 03 and 42.
06	PRINTS / SCHEMATICS	Use the equipment prints/schematics to verify the actual field conditions, i.e., transformer size, abnormal switching conditions, etc. against prints/schematics obtained from Supervision.
07	SECURITY / VANDALISM / SAFETY	Ensure safety and security equipment (such as locks and penta-bolts) are in place and in good working condition as specified in DTR Section 03. Check for signs of vandalism.
08	TOUCH POTENTIAL TESTING: (See NUMM Section 5.62)	
09	PROTECTIVE BUMPERS	Inspect protective bumpers to ensure they are present and in good condition, as required. Replace damaged bumpers.
10	COVER / GRATE	Ensure all covers or grates are securely locked or bolted in position.
11	OIL LEAKS	Inspect equipment for signs of oil leaks.
12	VEGETATION	Inspect for vegetation for intrusion into the equipment.
13	OBSTRUCTIONS / ACCESSIBILITY	Ensure there are no obstructions (i.e., shrubs, fences, buildings, foreign material, objects, etc.) and that the area is accessible as specified in DTR Section 42.
14	CONDITION OF RISER	Inspect the general condition of the riser and ensure it is secured to a pole.
15	POLE NO. / FUSE SIZE	Ensure riser pole stencils are present and that the stenciled fuse size agrees with that on the DB map.
NOTE: IF Obstructions/vegetation prevent accomplishment of the internal inspection STOP. The following internal inspection steps need not be performed:		
16	BARRIERS (ELECTRICAL)	Ensure electrical barriers are in place and in good condition.
17	GROUNDS	Ensure that all grounds, neutral, and drain wire connections, such as primary, secondary, transformer, telephone, etc. are in place and in good condition.
18	PRIMARY / SECONDARY EQUIPMENT	Ensure that primary/secondary equipment, such as bushings, insulators, arresters, elbows, terminators, connectors, cable taps, dead-end receptacles are in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.
19	INDICATORS	Inspect indicators including - temperature, oil level, fault-read, record, and reset as applicable. Test fault indicators per DTR Section 44 and ensure they are in good condition and working. Check fault indicator's date and replace older style indicators, if found. Ensure proper installation per DTR 44.222 -.223 & verify 2.5" min. spacing to ensure proper operation.
20	PIT / HANDHOLE (CABLE)	Check the cable pit / hand-hole for silt, debris, and corrosion.
21	DEFLECTOR PLATE	Ensure deflector plates are installed, as required for the specific equipment type.
22	MOUNTING HARDWARE	Check the mounting hardware to ensure it is stable and free from corrosion.
23	ELBOW ARRESTERS	Inspect elbow arresters are present and in good condition, as required.

24	SWITCH GEAR COVERS	Ensure switchgear covers are in place and are in good condition. Details for performing switchgear maintenance are provided in a separate chapter.
25	DEAD-END CAPS ON UNUSED BUSHINGS	Inspect dead-end caps on unused bushings are present and in good condition, as required.
26	INFRARED INSPECTION ON INDUSTRIAL AND COMMERCIAL EQUIPMENT: (See TD 853)	
	NOTE ANY CONDITIONS THAT REQUIRE FOLLOW-UP REPAIR ▶ Obstruction/vegetation which DOES NOT require a tree crew and more than 1 hour to clear need not be reported for follow up repair. In addition, the severity of obstructions must be verified by supervision as a condition for a CWO to be initiated for obstructions and/or vegetation.	

- **NOTE**: This use of this form is optional, and it is intended for use as a Worker's aid – not for use as a permanent record.

6.11 – Direct Buried Inspection Worksheet

Work Request No:	**AWC:**	**Town:**

Enter notes regarding repairs that are still required in the following section:

Severity of Obstructions must be verified by Supervision and Corrective Work Orders initiated only if it would require a tree crew and/or more than 1 hour to clear.

DB Name	Structure #	Structure Type	PCB Label Present?	Repairs Required

APPENDIX 6

CAPACITOR BANK INSPECTION

5.05 Capacitor Banks

General Description

Banks of capacitors are used to improve the power factor on the system. Other benefits include reducing system losses and improved voltage control. Capacitors are voltage sensitive and will not tolerate an extended over voltage condition of more than 110 percent of the nameplate rating without deterioration and eventual failure. Because of their electrical characteristics, they are susceptible to large inrush currents, discharge currents, and transient voltage peaks, each of which can reduce the expected life of the individual capacitor or increase the equipment servicing requirement of the bank.

Capacitors store energy in the form of electrical charge. They are designed with internal resistors that are intended to discharge to 50 volts within 5 minutes after disconnection from the voltage source. It is important to allow this period to expire before applying grounds to a de-energized capacitor bank, in order to prevent damage and/or hazards resulting from high discharge currents. Note that newer capacitors have discharge resistors, but older ones may not. Check the Capacitor breaker with an approved audible tester.

Capacitor banks are applied within substations and on poles on the system. Substation capacitor banks are made up of one or more series groups of capacitor cans often connected in parallel. Individual capacitors are normally provided with fuses. A blown fuse may be a sign of a failed capacitor. Since this could result in poor operation of the bank and/or damage to other capacitors within the bank, any capacitor with a blown fuse should be tested. Any capacitor suspected to be damaged (i.e., bulged tank, partial shorting per test results, etc.) should be replaced prior to re-energizing the bank. Failed capacitors must be handled carefully, due to the possible presence of gasses under pressure.

Capacitor Banks can be switched or not switched. Capacitor switches are devices that require periodic maintenance. For information on servicing capacitor switches, see the chapters on Circuit Switchers and Oil & Vacuum Switches.

Pole-Top capacitor banks are generally protected by fused cutouts. As with substation capacitor banks a blown fuse may indicate a failed capacitor unit.

Pole-Top capacitors require little maintenance. Scheduled inspections should be made before the heavy load season (typically from November to March) to ensure the equipment is operating properly. The components to inspect include capacitor cans, cutouts, oil switches, vacuum switches, arresters, control settings, control and radio batteries, and grounding.

Capacitor fuse(s) often blow with no visible damage, or indication of failure, of the capacitor. Failures of the newer all-film capacitors are particularly hard to discern since they generate considerably less gas than paper-film capacitors.

Field inspection of capacitors, at best, only indicates some probability that a capacitor has ***not*** failed. Field inspections provide no assurance as to the functional condition and expected life of a capacitor.

Facilities/Equipment

- Substation Capacitors – Rack-Mounted or Metal-Enclosed
- Pole-Top Capacitor Banks

5.05.1 Inspection and Maintenance Activity Schedules

WARNING: Wait at least FIVE MINUTES after de-energizing the capacitors before beginning to service them.

5.05.1.1 Table 1 – Capacitor Maintenance Intervals

Substation Capacitor Bank Maintenance Schedule	Interval
Time-Directed Maintenance	
Routine Check – Energized (Rack Mounted and Enclosed)	1M
Major Inspection – De-Energized (Enclosed only) (**Note 1**)	1Y
Condition-Based Maintenance (CBM) – S/S only	
Fuse replacement (replace if failed)	A/R
Major Test - De-Energized	A/R
Major Maintenance – De-Energized	A/R
Unit replacement (physical damage or failed test)	A/R
Block openings (if signs of animal or debris entry)	A/R
Clean the unit (if contaminated)	A/R
Repair all defects as they are found during Inspection and Test.	A/R
Pole-Top Capacitor Bank Maintenance Schedule	**Interval**
Time-Directed Maintenance	
Inspection	1Y
Infrared - Backbone only, while energized	1Y
Condition-Based Maintenance (CBM)	
Perform Test	A/R
Scheduling Requirements	
Perform Capacitor Inspection at same time as controller inspection	A/R
Maintain attached Potential Transformer at time of Capacitor Inspection, if possible.	A/R

Capacitor Bank - 69kV and above Maintenance Schedule	Interval
Time-Directed Maintenance	
Routine Check – Energized	1M
Infrared Inspection	6M
Major Inspection – De-Energized (**Note 1**)	1Y
Condition-Based Maintenance (CBM)	
Fuse replacement (replace if failed)	A/R
Major Test - De-Energized	A/R
Major Maintenance – De-Energized	A/R
Unit replacement (physical damage or failed test)	A/R
Block openings (if signs of animal or debris entry)	A/R
Clean the unit (if contaminated)	A/R
Diagnostic Testing	A/R
Repair all defects as they are found during Inspection and Test.	A/R
Continuous Monitoring	
Overvoltage condition	C
Imbalanced condition.	C
Scheduling Requirements	
Perform Capacitor Inspection at same time as controller inspection	A/R
Maintain attached Potential Transformer at time of Capacitor Inspection, if possible.	A/R

In **Table 1**, the type of maintenance is listed in the left column and the interval required for that type of maintenance is listed in the right column. For example, the interval for a **Major Inspection** of a Substation Capacitor is **1Y** (or 1 Year). The abbreviations used for the intervals are:

Y = Year, i.e. 2Y = 2 Years **M** = Month, i.e. 1M = 1 Month

A/R = As Required

Note 1 = The Major Inspection for enclosed units is to replace one of the monthly Routine Checks, so that the unit is only maintained 12 times per year.

5.05.2 Substation (S/S) Capacitor Maintenance Categories

See EMP Instruction 6.05 for details on performing the following maintenance activities.

Condition-Based

Repair all defects as they are found.

Time-Directed

5.05.2.1 Routine Check - Energized

Rack-Mounted Units and Metal-Enclosed Units

5.05.2.2 Major Inspection – De-Energized

Metal-Enclosed Units Only

5.05.2.3 Major Test – De-Energized

Rack-Mounted and Metal-Enclosed Units

5.05.2.4 Major Maintenance - De-Energized

Rack-Mounted and Metal-Enclosed Units

5.05.2.5 Infrared Testing – Rack Mounted Only

5.05.3 Pole-Top Capacitor Maintenance

See EMP Instruction 6.05 for details on performing the following maintenance activities.

Time-Directed

5.05.3.1 Pole-Top Capacitor Inspection

5.05.4 Capacitor – 69KV and Above Maintenance

See EMP Instruction 6.05 for details on performing the following maintenance activities.

Time-Directed

5.05.4.1 Routine Check - Energized

Rack-Mounted Units and Metal-Enclosed Units

5.05.4.2 Major Inspection – De-Energized

Metal-Enclosed Units Only

5.05.4.3 Major Test – De-Energized

Rack-Mounted and Metal-Enclosed Units

5.05.4.4 Major Maintenance - De-Energized

Rack-Mounted and Metal-Enclosed Units

5.05.4.5 Infrared Testing

5.05.5 Failure Finding

Failures of capacitors shall be documented in the equipment failure reporting system used by your region (EFRS, UPER, or Cascade, as appropriate) and placed in “To Eng” status for review by Distribution Standards..

5.05.6 References

Supporting References include:

- TD 832, “Capacitor Bank Inspection”
- Accident Prevention Manual – “Capacitors”
- NoMAX 1000 & 2000 series capacitor control Instruction Manual
- Fisher Pierce POWERFLEX Instruction Manual
- Supervisors’ Briefing Sheet No. SBS-05-017. Issued 12-08-2005
- Eversource Employee Safety Manual

5.05.7 Capacitor Maintenance Documentation

The maintenance activities and their schedules are based on industry experience, manufacturer’s recommendations, feedback from service technicians, and the subject matter experts.

Requirement	Basis
Substation Capacitors	
Routine Check – Energized @ 1M interval	Monthly inspections performed energized have historically been the accepted frequency cycle for this equipment. No information, either internal or external to Eversource, has been found to suggest a change to this frequency cycle is warranted.
Major Inspection (Metal-Enclosed only) – De-energized @ 1Y	Manufacturer’s literature recommends periodic de-energized maintenance, but does not provide a recommended frequency. Because components of a metal enclosed bank cannot be inspected during the monthly inspection, a de-energized inspection on an annual basis is necessary.
Pole Top Capacitors	
Inspection 1Y (Minimum)	A yearly inspection (at a minimum) has historically been the accepted frequency cycle for this equipment, as recommended by the MFR. No information, either internal or external to Eversource, has been found to suggest a change to this frequency cycle is warranted. This is supported by TD832 that indicates “One capacitor inspection is required annually in the spring. An optional inspection may be performed in the fall.”
Capacitors – 69KV and above.	
Infrared Inspection 6M(Minimum)	Thermography should be performed every 6 months with capacitors in service.

Capacitor Bank Maintenance

Before You Begin

Ensure that all employees are properly trained and qualified to perform this work; and all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:

- TD 211, “When to Wear FR Clothing”
- Eversource Employee Safety Manual
- TD 832, “Capacitor Bank Inspection”
- TD 800, “Distribution System Protective Work Clearances” (Connecticut and Western Massachusetts only)
- DTR 19.133 – “Capacitor Fusing Guide”
- New Hampshire Procedure CO-1155, “Isolation of Capacitor Banks on Distribution Circuits”
- TD 703 – Temporary Protective Grounds for Personnel in Substations
- TD 855 – Grounding for Personal Protection on Overhead Lines

Capacitor Maintenance Instructions

Routine Check – Energized Substation

Rack-Mounted Units

1. Check the fence enclosure, warning and caution signs, and locks for proper installation and condition (if applicable).
2. Visually check all fuses.
3. Check for oil leaks.
4. Visually check the physical condition of each capacitor.
5. Visually check for objects or animals / birds’ nests on the capacitors and on the rack.
6. Visually check any associated primary connected equipment (i.e., switches, lightning arresters, reactors) for abnormalities.
7. Visually check the breaker or interrupter counter(s), if applicable.
8. Visually check the controls (i.e., voltage, current, time clock, radio and lights), if applicable, for proper operation without cycling the equipment.
9. Listen for unusual noises.
10. If applicable, visually check the condition of the control cable, if possible.

11. Record the operations counter reading and other conditions pertinent to the unit (i.e., targets, fuses).
12. Notify Supervisor & create MxO Alert or Work Order if unusual conditions found.

Metal-Enclosed Units

1. Visually check the enclosure for damage and security (i.e., proper locking, unrestricted ventilation, signs of animal entry).
2. If the breaker, switch, or interrupter is safely accessible, visually check the condition and counter for normal operation without cycling the equipment.
3. If applicable, check the condition of the control cable, if possible.
4. Visually check the controls (i.e. voltage, current, time clock, radio and lights), if applicable, for proper operation without cycling the equipment.
5. Record the operations counter reading and other conditions pertinent to the unit (i.e., targets, fuses).
6. Check for oil leaks, if possible.
7. Listen for unusual noises.
8. Notify Supervisor & create MxO Alert or Work Order if unusual conditions found.

Major Inspection – De-Energized – Substation

NOTE
Prior to beginning maintenance, ensure that all switching, and notifications are performed in accordance with Company requirements.

Metal-Enclosed Units Only

1. Isolate and ground the capacitor bank using appropriate operating and safety procedures (allow 5 minutes before grounding bank after isolation).
2. Remove the capacitor bank from service in accordance with Company requirements.
3. Visually inspect the bank for the following:
    - Bulging cans
    - Oil leaks
    - Cracked housings

4. Check the ground switch and interlocking mechanism, if applicable, for damage or abnormalities.
5. If applicable, open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.
6. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
7. If applicable, check the condition of ventilators and filters.
8. If applicable, check the fans and thermostats, if applicable, for proper operation.
9. If applicable, check all fuses.
10. If applicable, check all capacitor tanks and connections for abnormalities.
11. If applicable, clean the unit before re-energization if it is dirty.
12. If applicable, remove Worker's grounds and short circuits from the bushings, if installed.
13. If applicable, disconnect the phase jumpers between the capacitor cans, if installed.
14. Calibrate and functionally checked monitoring equipment (relays, etc) used to alarm or trip the bank under abnormal conditions.
15. Test any capacitors found to have blown fuses as follows:
    a) Review the capacitance meter manufacturer's instructions.
    b) Calibrate the capacitance meter.
    c) Connect test leads to capacitor-can bushings.
    d) Ensure good test lead connection.
    e) Measure the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTE

Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.

The capacitance meter test may not always be correct. A failed capacitor may read within the range that indicates that the capacitor is good. Because this is not a conclusive test, every precaution shall be taken when energizing a capacitor.

1. Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:
2. Compare test results to the indicated values for the size and voltage of the can.
3. Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.
4. If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.

5. Replace failed capacitor can(s) if visual inspection and / or capacitance test results indicate capacitor can failure(s). Refer to TD 832, “Capacitor Bank Inspection”.
6. Restore the capacitor bank to service in accordance with Company requirements.
7. Check the operation of the oil switches when initiating a close (to re-energize the bank).

Major Test – De-Energized – Substation

Rack-Mounted *and* Metal-Enclosed Units

1. Test the voltage, current, time and/or radio operating controls for proper operation; check and verify their settings.

NOTE

Prior to performing the remainder of this maintenance, ensure that all switching and notifications are performed in accordance with Company requirements.

2. Isolate and ground the capacitor bank using appropriate operating and safety procedures. Allow five minutes before grounding the bank after isolating it.
3. Remove the capacitor from service in accordance with Company requirements.
4. Visually inspect the bank for the following:
    - Bulging cans
    - Oil leaks
    - Cracked housings
5. Open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.
6. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
7. Check the condition of ventilators and filters.
8. Check the fans and thermostats, if applicable, for proper operation.
9. Operationally check all associated switches and interlocking mechanisms (disconnect, ground, vacuum, etc.).
10. Wipe clean all insulators, bus supports, fuses, and bushings.
11. Check all capacitor tanks and connections to ensure that connections are tight and that there are no abnormalities.
12. Visually check and verify proper fusing of capacitors.
13. Check for blown fuses.

14. Test any capacitors found to have blown fuses as follows:
    a) Review the capacitance meter manufacturer's instructions.
    b) Calibrate the capacitance meter.
    c) Connect test leads to capacitor-can bushings.
    d) Ensure good test lead connection.
    e) Measure and record the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTE

Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.

NOTES:

- Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.
- The capacitance meter test may not always be correct. A failed capacitor may read within the range that would indicate that the capacitor is good. Because this is not a conclusive test, every precaution shall be taken when energizing a capacitor.

2. Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:
    a) Compare test results to the indicated values for the size and voltage of the can.
    b) Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.
    c) If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.
3. Replace failed capacitor can(s) if visual inspection and / or capacitance test results indicate capacitor can failure(s). Refer to TD 832, "Capacitor Bank Inspection".

NOTE

See Appendix 2 for a matrix to be used for determining when to replace capacitors based on inspection findings and maintenance history.

Clean the unit before re-energization, if it is dirty.

Restore the capacitor bank to service in accordance with Company requirements. Check the operation of the oil switches when initiating a close (to re-energize the bank).

Major Maintenance - De-Energized - Substation

Rack-Mounted and Metal-Enclosed Units

1. Test the voltage, current, time and/or radio operating controls for proper operation; check and verify their settings.

NOTE

Prior to performing the remainder of this maintenance, ensure that all switching and notifications are performed in accordance with Company requirements.

1. Isolate and ground the capacitor bank using appropriate operating and safety procedure (allow 5 minutes before grounding bank after isolating).

Remove the capacitor from service in accordance with Company requirements.

2. Visually inspect the bank for the following:
   - Bulging cans
   - Oil leaks
   - Cracked housings
3. Open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.
4. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
5. Check the condition of ventilators and filters.

Check the fans and thermostats, if applicable, for proper operation.

Test the voltage, current, time and/or radio operating controls for proper operation; check and verify settings. (If the bank is de-energized, it may not be possible to functionally check the controls. Functional check of a bank should be done prior to switching it out. This will allow for repairs to the controls while the bank is out.)

Operationally check all associated switches and interlocking mechanisms (disconnect, ground, vacuum, etc.).

Wipe clean all insulators, bus supports, fuses, and bushings.

Check all capacitor tanks and connections to ensure that connections are tight and that there are no abnormalities.

Visually check and verify proper fusing of

capacitors. Check for blown fuses.

Test any capacitors found to have blown fuses as follows:

a) Review the capacitance meter manufacturer's instructions.
b) Calibrate the capacitance meter.

c) Connect test leads to capacitor-can bushings.

d) Ensure good test lead connection.

e) Measure the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTES:

- Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.
- The capacitance meter test may not always be correct. A failed capacitor may read within the range which would indicate that the capacitor is good. Because this is not a conclusive test, every precaution shall be taken when energizing a capacitor.

Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:

f) Compare test results to the indicated values for the size and voltage of the can.

g) Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.

h) If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.

Replace failed capacitor can(s) if visual inspection and / or capacitance test results indicate capacitor can failure(s). Refer to TD 832, “Capacitor Bank Inspection”.

NOTE: See Appendix 2 for a matrix to be used for determining when to replace capacitors based on inspection findings and maintenance history.

Clean the exterior of the capacitor can, if it is dirty.

Test the breaker, interrupters, or switches as directed in their individual sections if on cycle with this work activity.

Replace any faulty equipment prior to returning the capacitor bank to

service. Restore the capacitor bank to service in accordance with

Company requirements.

Check the operation of the oil switches when initiating a close (to re-energize the bank).

Pole-Top Capacitor Maintenance (Refer to TD 832)

1. Visually inspect the bank for the following:
   - Bulging cans
   - Oil leaks
   - Cracked or broken insulators, if possible
   - Loose connections, if possible

- Blown fuses
- Blown arresters
- Grounds and grounding connections

Visually inspect the Pole, related equipment, and surrounding area as follows:

- Verify the Pole Number is present and correctly installed.
- Verify Tree/Vegetation growth is not encroaching on the equipment.
- Verify a continuous ground wire is present from the pole base to the capacitor bank.
- Verify a ground rod is present at the base of the pole.
- Verify a ground wire is present between the ground rod and system neutral.
- Verify that oil switches and vacuum interrupters are in good condition.
- Verify that radio-controlled switches are in good condition. Verify that all control switches are in their normal positions.

Schedule a replacement of the capacitor can if any obvious problems are found, such as physical damage etc.

- If a fuse is blown, test the capacitor.

From capacitor control, record the voltage, KVAR, and Power Factor. (Note: this information may not be available on some controls.) Initiate a close. The recorded values should have changed because of the added capacitance.

NOTES:

- Refer to PR-153 (Appendix 3 of this document) for a description of SC 571918, Transformer and Capacitor tester.
- A satisfactory visual inspection is an indication of a good capacitor can only.
- If the capacitor is not functional and has oil switches, the bank should be replaced with new.

Continuous Monitoring

Capacitor banks 69kV and above

1. Continuous monitoring of the input voltage and voltage or current imbalance within the capacitor banks is performed via SCADA alarm monitoring when the capacitor banks are in operation.

Condition Based Maintenance

Diagnostic Testing (performed with Bank de-energized)

1. Capacitor can values are recorded.
2. Neutral voltage imbalance protection relaying (if utilized) is tested for proper operation and settings are verified.

3. Over-voltage protection relaying (if utilized) is tested for proper operation and settings are verified.

Failure Finding: (Refer to TD 832)

1. See Appendix 2 for a matrix to be used for determining when to replace capacitors based on inspection findings and maintenance history.

- ***Replace*** the entire capacitor bank (see Appendix 2):
  - If there have been three or more can failures on the capacitor bank.
  - If there have been more than two trips to the capacitor bank for repairs other than Cans and Switches.
  - If the capacitor is not functional and has oil switches.
- ***Repair*** the capacitor bank if none of the above conditions for replacement exist. (See Appendix 2.)

Appendix 1 – Capacitor Test Benchmarks

System Line Voltage: kV	Capacitor-Can Voltage Rating: kV	Capacitor Rating: Mircrofarads *			
		Kvar	Ideal[1]	-5%[2]	+15%[3]
4.16Y/2.4	2.40	15	6.90	6.555	7.935
		25	11.50	10.925	13.225
		50	23.0	21.850	26.450
		100	46.0	43.700	52.90
4.8Δ 8.32Y / 4.8	4.80	15	1.725	1.639	1.983
		25	2.875	2.731	3.306
		50	5.751	5.463	6.614
		100	11.50	10.925	13.225
		200	23.0	21.85	26.45
12.4Y / 7.20	7.20	50	2.556	2.428	2.939
		100	5.112	4.856	5.879
		150	7.668	7.284	8.818
		200	10.224	9.713	11.757
13.2Y / 7.62	7.62	50	2.282	2.168	2.624
		100	4.564	4.336	5.249
		200	9.128	8.671	10.498
13.8Y / 7.96	7.96	50	2.09	1.986	2.404
		100	4.18	3.971	4.807
		200	8.36	7.942	9.614
		100	0.668	0.634	0.768

34.5 / 19.92	**19.92**	150	1.002	0.952	1.152
		200	1.336	1.269	1.536
		300	2.003	1.903	2.304
		400	2.671	2.538	3.072
23.0Y / 13.28	**13.28**	100	1.503	1.428	1.728
		200	3.006	2.856	3.457
		300	4.508	4.282	5.184
27.6Y / 15.93	**15.93**	200	2.089	1.984	2.402
115	**17**	200		1.84	2.02
115	**17**	300		2.75	3.02
115	**17**	400		3.67	4.04

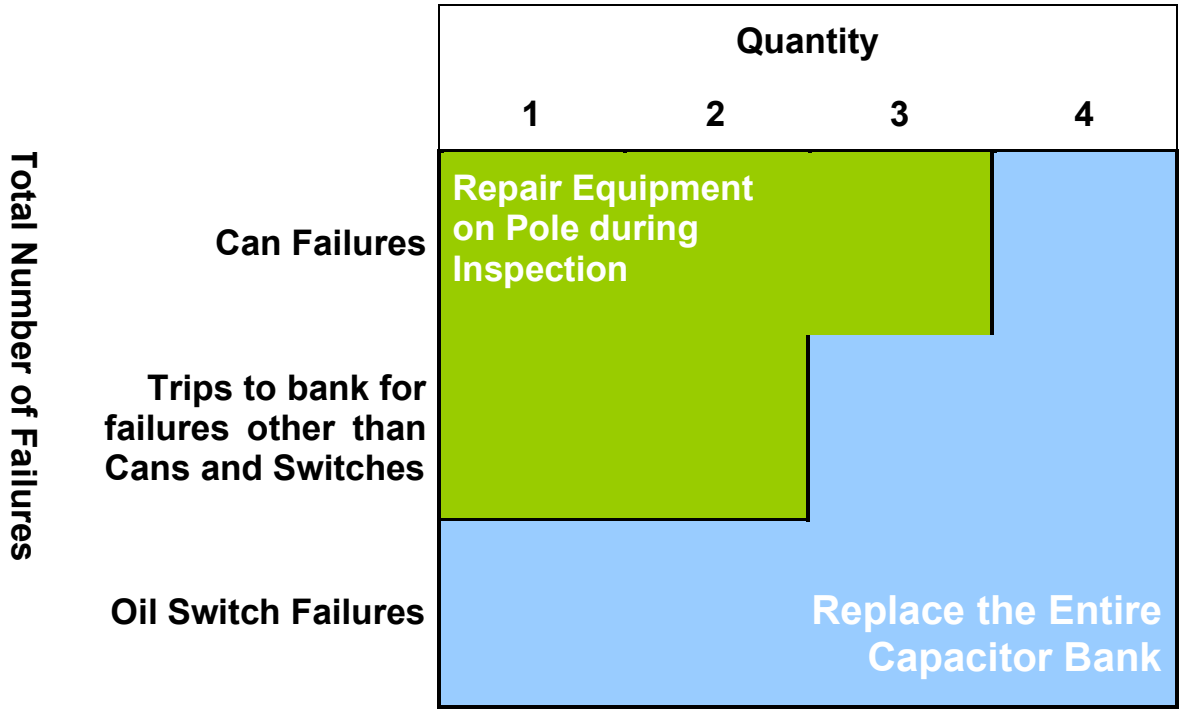
* Capacitor microfarads = 2.65 x (kVAR ÷ kV^2)

(1) This is an ideal capacitor test reading.

(2) Replace the capacitor can if the reading is below this value.

(3) Replace the capacitor can if the reading is above this value.

Appendix 2 – Eversource Capacitor Replacement Decision Matrix



Appendix 3 –

Northeast Utilities System

CL&P Distribution Construction Methods

PRODUCT REVIEW

 # 153 Dated 07-31-03
Name: A. H. Palmer

Hand Held QUICK CHECK Transformer & Capacitor Tester

This product Review is being issued to make everyone aware that a new hand held transformer and capacitor tester has been added to the Tool and Equipment Standards Catalog. This tester has been used favorably by PSNH personnel. This tester features large copper alligator clips with heavy duty boots and rubber insulated coiled test leads, powered by a 9volt battery, bright LED indicators, audible alarm, built-in self test feature, one button test, and comes with a carrying case.

This tester can be used for quick and easy checks of de-energized transformers & capacitors and the connections made to them. It can test for both primary and secondary shorts or opens (including internal fuses and breakers) in either single or three phase transformers, including potential and other instrument transformers. It can test capacitors individually or connected in banks for both shorts or opens.

Stock Code: **571918**



PLEASE SHARE THIS INFORMATION WITH ALL APPROPRIATE PERSONNEL

PR153

APPENDIX 7

DISCONNECT SWITCHES

5.15 Substation Disconnect Switches

1.0 Definitions

1.1 Loadbreak Disconnect - is a switch installed for isolation purposes or for changing the configuration of active power circuits. It has load-make and load-break ratings in Amperes.

1.2 Non-loadbreak Disconnect – is a switch installed for isolation purposes with very restricted or no load-make or load-break capabilities. It can be used to energize or de- energize unloaded bus or bus segments only within the substation. It can be used to energize or de-energize unloaded circuit breakers, lightning arrestors, and other switches.

1.3 Motor Operated Control – Some three-phase disconnects are equipped with electric motor operators to open and close them. These disconnects have the ability to be operated locally or remotely.

1.4 SCADA – Some disconnect switches are connected to SCADA – an automated system that monitors the switch position, current and voltage, and provides data to a remote location. It also allows for remote operation of the switch if the switch is motor operated.

2.0 Introduction

2.1 Switches are essential elements of the electrical power distribution systems. They provide visible air gap isolation of equipment and line sections for safe examination, maintenance, and repair.

2.2 Switches are built in a variety of physical forms to accommodate the various requirements of electrical clearances, operational requirements, and space limitations.

2.3 Some substation disconnects include loadbreak hooks for use with a loadbreak tool.

2.3.1 To open the switch under load, an approved loadbreak tool or approved device shall be used.

2.3.2 Follow the instructions provided with the loadbreak tools. See DTR Substation18.41 for the complete list of applications and restrictions for Loadbreak and Non- loadbreak disconnect switches.

2.4 Switches can be divided into three main categories:

2.4.1 Single Phase Disconnect Switches

.1.1Single phase disconnects are defined as a switch opening one connection only, either a single-phase circuit, one phase of a multiphase circuit, or a miscellaneous application such as a neutral circuit switch.

2.4.2 Three Phase Disconnect Switches

21. Three phase disconnects are defined as a switch associated with a mechanism that causes switches of the three phases to operate simultaneously.

22. These switches are Gang-Operated (GOD), sometimes referred to as Gang-Operated Air Brake (GOAB).

23. The most common gang-operated disconnect switches are the air-break type manufactured with ratings up to 5000-amperes in voltage classes ranging from 34.5kV-345kV.

24. They are used at substations, switching structures, and on the lines for isolating transformer banks and other apparatus.

25. They are also used for sectionalizing. Although they can be MODs (Motor-Operated Disconnects), they are more commonly provided with a switch handle for hand operation.

26. This type of switch is ideal because it lends itself to operation from the ground, often permitting service to be restored to sections of the circuit without pole climbing.

2.4.1 Regulator Bypass Switches

.3.1. Bypass switches are generally used at regulator installations to provide a quick, reliable means of taking such apparatus in and out of service without de-energizing the feeder circuits and to prevent winding burnouts from open-circuit windings.

2.5 Facilities/Equipment

2.5.1 Line Bypass, Disconnect, and Interrupter Switches

NOTE: The inspection and maintenance for single phase Pole-top disconnects is the same for “inline suspension” disconnects.

3.0 Reference Documents

WMS 60.10-234 Substation Transformer Thermography for CT,
WMS 59.04-234 Substation Disconnect Switch Maintenance for CT,
TD 853 Infrared Thermographic Inspections

4.0 General

4.1 Only trained and qualified employees shall perform inspections and preventative maintenance on air disconnects switches

4.2 Prior to the start of work

4.2.1 Review all equipment drawings and reference materials.

4.2.2 Personnel are wearing the appropriate personal protective equipment (PPE).

5.0. Inspection and Preventative Maintenance Schedules

Inspection Type	Inspection Interval
Time-Directed Maintenance (Energized PM & Inspections)	
Visual Inspection	1M
Infrared Inspection (GODs & S/S)	6M
Motor Control Visual Inspection	3Y

Inspection Type	Inspection Interval
Inspection/Battery Replacement	3Y
Condition-Based Maintenance (CBM)	
Major Maintenance - De-Energized	A/R
Operational Test	A/R
Correct Abnormal Conditions (Any Visual Findings)	A/R

6.0 Time-Directed Maintenance (Energized PM & Inspections)

6.1 Visual Inspection: This inspection is performed to look for conditions that may require immediate attention or unplanned maintenance.

NOTE: A Visual Inspection is performed for those Substation Disconnects that are not practical to de-energize, even when the associated equipment is being maintained and is out of service. Units that fail this inspection shall be scheduled for maintenance or replaced if conditions warrant.

6.2 It can be used to determine the overall condition of the disconnect switch and if the disconnect switch requires replacement.

6.3 This interval has proven effective in detecting problems that could impact equipment performance.

6.4 The disconnect switch can be visually inspected for the following:

6.4.1 Insulators damage

6.4.2 Frayed or broken flexible connections,

6.4.3 Taps – from switch to line conductors and/or bus connections.

6.4.4 Overheating (visual)

6.4.5 Condition of operating mechanism

6.4.6 Alignment of blades and proper contact

6.4.7 Signs of abnormal discharge, alignment and tripping linkage on load breaking devices

6.4.8 Mechanical condition of frame

6.4.9 Condition or pitting or arcing horns, if applicable

6.4.10 Grounds and ground attachments for proper connections

6.4.11 Obstructions that might obstruct operation or create a contact hazard.

6.4.12 Debris that my hinder the performance of the switch– bird nests, kite string, etc. on switch.

6.4.13 Animal Protection – missing or damaged, if applicable

6.5 Infrared Inspection: Infrared inspection is a proven technique for locating “hot spots” on equipment and connections in order to identify conditions that can be corrected before they become serious problems.

NOTE: Infrared surveys are performed on Disconnect Switches in accordance with TD 853 – Infrared Inspections.

Refer to TD 853 – Infrared Inspections for the requirements and the interval at which inspections are to be performed.

There may be special infrared survey requirements for different regions. Specifically, for EMA downtown network Stations, disconnect switches inspected may be performed quarterly.

6.6 Motor Control Visual Inspection/Battery Replacement: This inspection is performed to look for conditions for the switch-control unit that may require immediate attention or unplanned maintenance. If applicable, also verify battery date and replace battery if it has expired or will expire before next scheduled maintenance. This interval has proven effective in detecting problems that could impact equipment performance. The disconnect switch can be visually inspected for the following:

6.6.1 Condition of the control cable

6.6.2 Condition of the control cabinet

6.6.3 Compartment heater condition

6.6.4 Condition of the indicating lights

6.65 Refer to Work Method/Procedure WMS 59.04-234 for CT, WMA & NH, and W10223 for EMA on how to perform a battery replacement for switch-control units where applicable.

NOTE: Routine Switch Controller maintenance consists of replacing the battery packs. The frequency of replacement depends on designed battery life, ambient temperature, float charge voltage and frequency of discharge. Industry experience has shown that batteries should be replaced every two years for hot environments and three years for colder environments.

7.0 Condition Based Maintenance (CBM)

7.1 Major Maintenance - De-Energized: De-Energized Major Maintenance is performed on substation disconnects that are difficult to de-energize and therefore receive Major Maintenance only when its associated equipment is taken out of service for maintenance.

7.1.1 Please refer to Work Method/Procedure WMS 59.04-234 for CT, on how to perform a major maintenance activity for substation disconnect switches.

7.2 Operational Test: The operational test is performed at the time of Major Maintenance.

7.2.1 Please refer to Work Method/Procedure WMS 59.04-234 for CT, on how to perform an operational test for substation disconnect switches.

NOTE: The Operational Test is performed at the time of Major Maintenance.

7.3 Correct Abnormal Conditions (Any Visual Findings): Correct any abnormal conditions found during maintenance or inspections.

8.0 Failure Finding

Failures of disconnect switches shall be documented in the 'Substation Equipment Failures Database' for review and discussion at the System Operations Review Committee (SORC) and Substation Equipment Committee (SEC) meetings.

WMS 59.04.234

1.0 Introduction

1.1 Generally, substation disconnect switches consist of a conducting blade, hinged at one end, and a stationary contact on the other, both terminals mounted on that conform to the common insulator requirements of BIL coordination.

1.2 Locking devices are provided to keep the disconnects from being opened accidentally or from being blown open during periods of heavy fault currents passing through them.

2.0 Reference Documents

ESOP 100 Switching and Tagging

M4-WP-3128 Vehicle Grounding Requirements

TD852 Lockout/Tagout for Electrical Equipment and Other Equipment Related Energy Sources

TD855 Grounding for Personal Protection on Overhead Distribution Lines

WMS 89.06-234 Protective Grounding Inside Substation

WMS 89.07-234 Vehicle and Equipment Grounding in Substations

WMS 89.11-234 Maintenance & Testing of Substation Protective Grounding Equipment

WMS 88.11-234 Substation Work Area Identification

WMS 88.12-234 Substation Fall Protection

WMS 86.01-234 Equipment Lubrication

3.0 Generals

3.1 Clearance shall be given by the System Control Center as specified under the provisions of the applicable Eversource switching authority. Refer to **ESOP 100**.

3.2 Check and validate any tags associated with the switch being tested.

3.3 Verify all prints and drawings being used are for the switch being tested.

3.4 When required, review associated print(s) to understand the tripping logic.

Procedure

4.0 Single Phase De-Energized Switch Maintenance

4.1 Verify the switch is de-energized, isolated, and tagged in accordance with **ESOP 100**.

4.2 Verify the switch and lines have been grounded in accordance with **WMS 89.06-234** and **WMS 89.07-234** prior to any maintenance activities.

4.3 Isolate the switch from all other possible energy sources in accordance with **TD852**, as required.

4.4 Check for broken plastic cams on the blades.

4.5 Inspect the insulators for breaks, cracks, burns, or cement deterioration.

4.5.1 Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist.

.1.1. Cleaning minimizes the possibility of flashover from the accumulation of foreign substances on the insulator surfaces.

4.5.2 Replace any broken or defective insulators immediately.

NOTE: The S&C disconnect switches require inspection / adjustment to ensure proper blade alignment. Refer to Appendix A “S&C Alignment Procedure” following the Operational Test section for instructions on adjusting the S&C Disconnect Switches.

4.6 Inspect the switch for:

4.6.1 Alignment

4.6.2 Contact pressure

4.6.3 Eroded contacts

4.6.4 Corrosion

4.6.5 Mechanical malfunction

NOTE: S&C Omni-Rupter® Switch blade contacts are greaseless and self-lubricating. Do not apply lubricant to the blade contacts.

4.7 Replace damaged or badly eroded components.

4.7.1 If contact pitting is minor, smooth the surface with clean, fine emery cloth or as the manufacturer recommends.

NOTE: Scotch-Brite™ may be used on silver contacts when a wire brush cannot be used.

4.8 For non-self-lubricating contacts ONLY:

4.8.1 Clean and lubricate the contacts with a thin film of manufacturer-recommended lubricant, i.e. non-oxide. Refer to **WMS 86.01-234**.

4.9 Operate the switch several times and check it for smooth operation.

4.10 Clean and lubricate the bearings with the manufacturer recommend lubricant, if applicable. Refer to **WMS 86.01-234**.

4.11 Inspect the blade latch for adjustment.

4.11.1 Ensure the blades move freely and still are rigid enough for proper alignment with contacts.

4.12 Perform resistance testing on the contacts for each phase using a micro-ohm meter connected bus-to-bus.

4.12.1 Record the results.
4.12.2 Perform resistance testing on the remaining components including the jaws, hinges, and connectors to determine their condition.

4.13 Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

4.14 Inspect inter-phase linkages, operating rods, levers, bearings, etc., to ensure that adjustments are correct, all joints are tight, and that pipes are not bent.

4.14.1 Clean and lubricate the switch parts, as required.
4.14.2 Check for simultaneous closing of all blades and for proper seating in the closed position.

4.15 Inspect the gear boxes for moisture that could cause damage due to corrosion or ice formation, if possible.

4.16 Inspect the flexible braids or slip-ring contacts used for grounding the operating handle and replace those showing signs of corrosion, wear, or having broken strands.

4.17 Power-operating mechanisms for switches are usually of the motor-driven type.

4.17.1 Follow the switch manufacturer's instructions for maintaining each mechanism. Check the limit switch including external switches for:

1.1. Poor contacts

1.2. Burned out coils.

1.3. Adequacy of supply voltage

1.4. Any other conditions that might prevent the proper functioning of the complete switch assembly.

4.18 Inspect the overall switch and working condition of operating mechanism:

4.18.1 Check that the bolts (including the piercing bolts on the operating shaft), nuts, washers, cotter pins, and terminal connectors are in place, properly torqued and in good condition.

4.18.2 Replace items showing excessive wear or corrosion.

4.18.3 Inspect all bus cable connections for signs of overheating or looseness.

4.19 Inspect and check all safety interlocks while testing for proper operation.

4.20 Inspect the switch to ensure equal pole closing and opening.

4.21 Ensure that each switch-pole toggle mechanism lies against its closed stop, as applicable.

4.21.1 Adjust the stop-bolt or crank-arm length as necessary. Refer to the manufacturer’s manual and Figure 1.

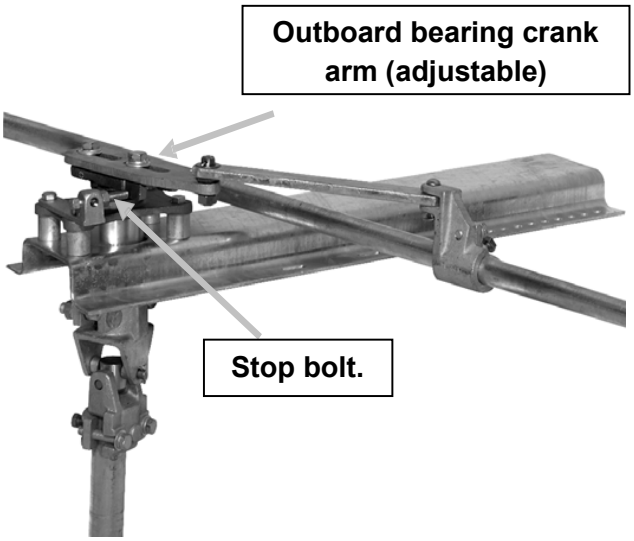


Figure 1 – Checking Switch Toggle Position on S&C Disconnect

4.22 Operate the MOD to ensure its smooth operation. Listen for grinding noises or other signs of wear or malfunction.

4.23 Record any abnormal conditions, any repairs made, and any repairs still needed into Cascade.

4.22 Check the battery date and replace the battery if it has expired or will expire before the next scheduled maintenance, if applicable.

4.25 Record any abnormal conditions.

4.25.1 Create Cascade Mx-work orders for all repairs.

5.0 3 Phase De-Energized Switch Maintenance

5.1 Verify the switch is de-energized, isolated, and tagged in accordance with ESOP 100.

5.2 Verify the switch and lines have been grounded in accordance with WMS 89.06-234 and WMS 89.07-234 prior to any maintenance activities.

5.3 Isolate the switch from all other possible energy sources in accordance with TD852, as required.

5.4 Check for broken plastic cams on the blades.

5.5 Inspect the insulators for breaks, cracks, burns, or cement deterioration.

5.5.1 Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist.

.1.1. This minimizes the possibility of flashover from the accumulation of foreign substances on the insulator surfaces.

5.5.2 Replace any broken or defective insulators immediately.

NOTE: The S&C disconnect switches require inspection / adjustment to ensure proper blade alignment. Refer to Appendix A “S&C Alignment Procedure” following the Operational Test for instructions on adjusting the S&C Disconnect Switches.

5.6 Inspect the switch for:

5.6.1 Alignment
5.6.2 Contact pressure
5.6.3 Eroded contacts
5.6.4 Corrosion
5.6.5 Mechanical malfunction

NOTE: S&C Omni-Rupter® Switch blade contacts are greaseless and self-lubricating. Do not apply lubricant to the blade contacts.

5.7 Replace damaged or badly eroded components.

5.7.1 If contact pitting is minor, smooth the surface with clean, fine emery cloth or as the manufacturer recommends.

NOTE: Scotch-Brite™ may be used on silver contacts when a wire brush cannot be used.

5.8 For non-self-lubricating contacts ONLY:

5.8.1 Clean and lubricate the contacts with a thin film of manufacturer-recommended lubricant, i.e. non-oxide. Refer to WMS 86.01-234.

5.9 Clean and lubricate the bearings with the manufacturer recommend lubricant, if applicable. Refer to WMS 86.01-234.

5.10 Inspect the blade latch for adjustment.
5.10.1 Ensure the blades move freely and still are rigid enough for proper alignment with contacts.

5.11 Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

5.12 Inspect inter-phase linkages, operating rods, levers, bearings, etc., to ensure that adjustments are correct, all joints are tight, and pipes are not bent or cracked.

5.12.1 Clean and lubricate the switch parts, as required. Refer to WMS 86.01-234.

5.13 Inspect the gear boxes for moisture that could cause damage due to corrosion or ice formation, if possible.

5.14 Inspect the flexible braids or slip-ring contacts used for grounding the operating handle.

5.14.1 Replace when broken or signs of corrosion or wear are present.

5.15 Power-operating mechanisms for switches are usually of the motor-driven type.

5.15.1 Follow the switch manufacturer's instructions for maintaining each mechanism. Check the limit switch including external switches for:

1.1. Poor contacts
1.2. Burned out coils.
1.3. Adequacy of supply voltage
1.4. Any other conditions that might prevent the proper functioning of the complete switch assembly.

5.16 Inspect the overall switch and working condition of operating mechanism:

5.16.1 Inspect the bolts (including the piercing bolts on the operating shaft), nuts, washers, cotter pins, and terminal connectors are in place and in good condition.

5.16.2 Replace items showing excessive wear or corrosion.

5.17 Inspect all bus cable connections for signs of overheating or looseness.

5.18 Inspect and check all safety interlocks and verify testing for proper operation.

5.19 Inspect the switch to ensure equal pole closing and opening.

5.20 Operate the switch to ensure its smooth operation. Listen for grinding noises or other signs of wear or malfunction.

5.20.1 Check for simultaneous closing of all blades and for proper seating in the closed position.

5.20.2 Check for simultaneous opening of all blades.

5.21 Record any conditions that require follow-up repair in Cascade.

5.21.1 Create Cascade Mx-work orders for all repairs.

6.0 Battery Replacement Instructions

6.1 Notify Dispatch before beginning work.

6.2 Ensure the battery cables are clearly marked at the battery terminal and battery charger ends to avoid improper connection.

6.3 Clearly mark the date of installation on the battery for replacement purposes.

6.4 Removing the old battery:

6.4.1 Open the front enclosure door.
6.4.2 Place the switch control on “local” control.
6.4.3 Ensure that voltage sensing is turned “OFF”, if applicable.
6.4.4 Decouple the unit.
6.4.5 Turn OFF the AC low voltage supply.
6.4.6 Open the DC knife blades.
6.4.7 Open the battery enclosure.
6.4.8 Disconnect the battery (negative terminal first, followed by the positive terminal) and remove it.

6.5 Installing the new battery:

6.5.1 Before installing the new battery, verify the settings on the constant burden battery charger as follows:

1.1. Short-circuit the output terminals of the battery charger with a jumper.

1.2. Turn ON the low voltage supply to energize the battery charger and verify that charging current reads 225 milli-amperes. Adjust the “burden adjust” to 225 mA, as necessary and lock it in.

1.3. Turn OFF the AC low voltage supply to de-energize the battery charger. Remove the short-circuiting jumper from the output terminals.

1.4. Turn ON the AC low voltage supply to energize the battery charger.

1.5. Using a voltmeter, verify or adjust the charger to a voltage output of 13.3 volts. DC. Adjustment is made using the “output adjust” control.

6.5.2 Turn OFF the AC low voltage supply to de-energize the battery charger.

6.5.3 Install the new battery and connect it – positive terminal first, followed by the negative terminal.

6.5.4 Perform a load check on the battery to ensure it is good.

6.5.5 Ensure the constant burden battery charger functions correctly as follows:

5.1. Clip the voltmeter leads to the output terminals of the charger and observe the battery voltage.

5.2. Turn ON the AC low voltage supply to energize the battery charger and observe the output voltage as well as the DC charging current.

5.3. Verify that as the output recovers to 13.3 volts DC, the charging current tapers off to a “trickle-charge” level.

6.5.6 With the AC low voltage supply still ON, close the DC knife blades.

6.5.7 Couple the unit.

6.5.8 Turn ON voltage sensing (if applicable).

6.5.9 Place the unit on “supervisory” or “auto” control.

6.5.10 Close and lock both enclosures.

6.5.11 Notify the dispatcher that the battery replacement is complete, and the switch is back in its normal state.

7.0 Operational Test

7.1 Perform the operational test in conjunction with maintenance of the equipment to which the switch is attached.

7.2 Ensure that the switch is bypassed or transfer the load before performing the test.

7.3 Record any abnormal conditions, repairs required, or repairs made in the comments section.

7.4 Follow-up repairs require the creation of Cascade Mx-work orders.

8.0 Appendix A – S&C Alignment Procedure

8.1 OPEN and CLOSE the interrupter switch vigorously through its full travel without hesitation at any point.

8.1.1 Be prepared to apply additional force to maintain full speed when operating effort increases as the switch blades engage the interrupters.

CAUTION: Failure to properly adjust the handle may cause contact overheating or arcing, damaging the blade contacts. Injury to operating personnel may result.

8.2 Adjust the stop plates to remove all excess play from the operating mechanism and to attain proper “windup” tension before energizing the switch.

NOTE: Slack in the operating pipe may allow the switch to creep out of the fully CLOSED position.

8.3 Loosen the bolts that secure the adjustable stop plates to the foot bearing support plate.

Refer to Figure A1.

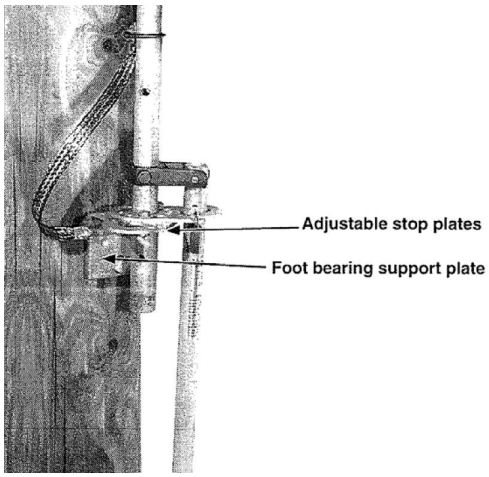


Figure A1 – Foot Bearing Assembly and Operating Handle Assembly

8.4 Place the switch in the fully OPEN position.

8.4.1 Adjust the OPEN position stop plate so that the handle, when lowered, fits into the OPEN-position slot.

8.5 Mark the location of the OPEN position stop plate on the support plate.

8.6 Fully CLOSE the switch. Apply sufficient pressure to the handle in the closing direction to remove all play in the operating-pipe linkage.

8.7 Adjust the CLOSED position stop plate so that the handle will require even greater pressure to force it into the closed-position slot.

8.8 Mark the location of the CLOSED position stop plate on the support plate.

8.9 While holding both stop plates in the previously marked positions, torque the bolts to secure the stop plates to the support plate.

8.10 Move the handle to the OPEN position.

8.10.1 Verify the handle, when lowered, fits firmly into the OPEN position slot.

8.11 Move the handle to the CLOSED position.

8.12 Verify:

8.12.1 All play in the operating pipe linkage has been taken up before the handle can be lowered into the CLOSED position slot.

8.12.2 Substantial pressure is required to force the handle into the closed-position slot.

8.13 Recheck and ensure that all clamp bolts and piercing set screws are properly tightened.

APPENDIX 8

POLE TOP REGULATORS

5.01 Regulators

1.0 Introduction

1.1 Regulators play a significant role in helping electrical loads operate most effectively at their rated voltage. It is important that the rated voltages supplied to these loads are maintained as nearly constant as possible.

NOTE: All specific maintenance requirements that are followed by a triangle Symbol "▲" are explained in the Maintenance Basis Documentation Section of this chapter.

2.0 Reference Documents

EMP 5.22 Infrared Inspections

EMP 6.01 Voltage Regulators

TD 861 Reporting Distribution Equipment Failures and Defects

3.0 Definitions

The abbreviations used for the intervals are:

3.1.1 Y = Year, i.e. 2Y = 2 Years

3.1.2 M = Month

3.1.3 A/R = As Required

4.0 Inspection and Maintenance Activity Schedules

Table 1 – Voltage Regulator Maintenance Intervals

Pole-Mounted Maintenance Schedule	Interval
Time-Directed	
Routine Inspection ▲	1Y
Condition-Based	
Major Maintenance	A/R (Note 1)
Correct any defects found during **Routine Inspection,** such as low oil level, faulty operation counter, etc.	A/R

Infrared Survey	A/R (Note 2)
Pad-Mounted Maintenance Schedule	**Interval**
Time-Directed	
Routine Inspection	1Y
Infrared Survey	(Note 2)
Condition-Based	
Major Maintenance	A/R
S/S Maintenance Schedule	**Interval**
Time-Directed	
Routine Inspection ▲	1M
Oil Sample (Substation Regulators Only)	5Y
Condition-Based	
Major Maintenance	A/R (Note 1)
Correct any defects found during **Routine Inspection,** such as low oil level, faulty operation counter, etc.	A/R
Infrared Survey	A/R (Note 2)

NOTES: 1. Major Maintenance for Substation Regulators is only required when the results of oil analysis indicate there is a problem with the Regulator and is typically performed at the shop. Major Maintenance for all Pole-top Regulators is performed at the shop whenever they are taken out of service.

2. Infrared surveys are performed on Regulators in accordance with the requirements of **EMP 5.22** – Infrared Inspections. Refer to **EMP 5.22** for inspection requirements and the interval at which inspections are to be performed.

3. The time interval between maintenance activities will depend upon frequency of tap-changer operation and the load on the Regulator. Regulators subjected to numerous overloads and a high load factor may require more frequent inspections than those carrying normal loads. The initial maintenance interval will be as listed above, and will be adjusted in the future, based on collected performance data.

5.0 Maintenance Categories

5.1 See EMP 6.01 for details on performing the following maintenance tasks.

Table 2 – Maintenance Categories

Type	Inspection Type	Energized / De-Energized
Time-Directed	Routine Inspection	Energized
	Oil Top-Off	De-Energized
	Oil Sampling	Energized or De-Energized
Condition-Based	Major Maintenance	De-Energized
	Return to Service	---
	Infrared Survey	See **EMP 5.22**

6.0 Failure Findings

6.1 Failures of devices shall be documented in the failure reporting system used by your region and appropriate for the asset class.

6.1.1 Distribution equipment failures shall be reported using EFRS. See TD 861 for additional information.

6.1.2 Distribution asset failures shall be documented using Maximo.

6.1.3 Stations asset failures shall be documented using CASCADE.

7.0 Voltage Regulator Maintenance Basis Documentation

Table 3 – Voltage Regulator Maintenance Basis Documentation

Requirement	Basis
Inspection Interval – 1Y	The Regulators manufacturer's maintenance manuals do not specify a time interval for inspection and oil sampling. They state that inspection and oil sampling functions are condition-based and are dependent upon the frequency of tap-changer operation and the load on the Regulator. Industry experience with Automatic Voltage Regulator performance testing as listed in: • Council Controls Working Group (WG) Recommendations Policy • U.S. Department of the Interior Bureau of Reclamation Denver, Colorado • US Navy -Publication Number: TM 5-684/NAVFAC MO 200/AFJMAN32-1082 recommends an annual inspection. Note: The NUMP, based on the Work Practice #M4-WP-3018 Rev. 1, recommends a 6-month inspection interval, but company experience has proven that a 1-year interval is sufficient for keeping the equipment reliable

Substation Oil Sample Interval – 5Y	Industry experience with Automatic Voltage Regulator performance testing as listed in: • Council Controls Working Group (WG) Recommendations Policy • U.S. Department of the Interior Bureau of Reclamation Denver, Colorado • US Navy - Publication Number: TM 5-684/NAVFAC MO 200/AFJMAN 32-1082 recommends a 5-year oil sampling frequency. The maintenance practice of many other utilities as it pertained to step voltage Regulators were examined to determine the frequency of their oil sampling. The examination revealed that some utilities perform an oil sample every two years, other never performed oil sampling. The manufacturer's instruction states that their Regulator are design for many years of trouble-free operation, without the need for any maintenance, and that maintenance is condition based. One manufacturer went as far as to say their Regulator could possibly function for 20 years without any maintenance. Several manufacturers suggest operation counts in the 100,000-count range as a basis for performing a Major Maintenance. Although each manufacturer states that they do not anticipate the need for frequency maintenance, periodic inspection including oil sampling would help to assure continuity of service. Based on these recommendations and of a review of Eversource's Regulator failure reports, in which no noticeable failures were observed over a five-year period; the 5Y or 50,000 operations count (based on application) oil sampling interval is being established on a Regulators. This replaces the previous 2-year oil sample interval. As data is collected, and examined, this interval may be adjusted.
Infrared Inspection	Infrared inspection is a proven technique for locating "hot spots" on equipment and connections in order to identify conditions that can be corrected before they become serious problems.

APPENDIX 9

RECLOSERS AND SECTIONALIZERS

5.44 Automatic Circuit Reclosers (ACR) & Sectionalizers

General Description

Reclosers sense and interrupt fault currents and automatically restore service after momentary outages. The automatic circuit recloser is essentially a self- contained device with the necessary intelligence to sense over currents, to time and interrupt fault currents, and to re-energize the line by reclosing automatically. If a fault is permanent, the recloser locks open after a preset number of operations, isolating the faulted section from the main part of the system. Automatic circuit reclosers installed at Eversource Energy:

- Can be either Single-phase or Three-phase
- Can have either Oil or Vacuum Interrupters
- Can have either Hydraulic or Electronic Controls
- Can be either Oil or Epoxy Insulated

Single-phase reclosers are used to protect single-phase lines such as branches or taps of a three-phase feeder. They can also be used on three-phase circuits where the load is predominantly single phase.

Single phase reclosers installed at Eversource Energy include (not a complete list) Type H, 4H, V4H, L, V4L, VXE15, D, E, 4E, V4E, and DV. (See Appendix 2.)

Three phase reclosers are used in multiple applications: As main feeder breakers at the substation source, as sectionalizing and tie devices with over current protection within auto loops; and for over current protection on major three phase laterals. Reclosers within auto loops operate based on local current and voltage sensing to re-sectionalize circuits to limit the number of customers interrupted by a fault on a circuit backbone. The majority of three phase reclosers are monitored as part of the DSCADA System, providing remote control and data acquisition capability.

Three phase reclosers installed at Northeast Utilities include (not a complete list) Type 6H, V6H, W,WE, VWE, WVE27, VWVE27, NOVA27, WVE38X, VWVE38X, VSO12, and NOVA38. (See Appendix 2.)

Recloser Controls provide the intelligence that enables a recloser to sense over-currents, select timing operation, time the tripping and reclosing functions, and finally lockout the circuit when required. There are two basic types of controls used: an integral hydraulic control or an electronic control located in a separate cabinet.

- **Hydraulic recloser controls** are used in most single-phase reclosers and in three-phase recloser types 6H, V6H, and W. The controls are an integral part of the recloser. With this type of control, an over-current is sensed by a trip coil that is connected in series with the line.
- **Electronic recloser controls** are used in most three-phase reclosers and in the single-phase Cooper recloser types VXE and NOVA.

5.44.1 Inspection and Maintenance Schedules

Table 1 –Recloser Maintenance Intervals

Recloser Maintenance Schedule	**Contacts in Vacuum**	**Contacts in Oil**
Time-Directed Maintenance		
Check – Energized S/S	1M	1M
Check – Energized (SCADA) – Pole Top (**Note 1**)	1Y	1Y
Check – Energized (Non-SCADA) Pole-Top Electronic	2M	2M
Check – Energized Pole-Top Hydraulic	1Y	1Y
Inspection – Energized (Infrared)	1Y	1Y
Major Maintenance – De-Energized	N/A	12Y
Condition-Based Maintenance		
Major Maintenance – Triggered by Contact Life or Duty Cycle. (**Note 2**)	≤95%	≤ 95%
Major Maintenance – Triggered by Fault Operations	200	N/A
Major Maintenance Evaluation– Triggered by Operations Count. (**Note 3**)	N/A	100
Scheduling Requirements		
Schedule maintenance of the attached Potential Transformer at the same time as the recloser, if applicable.		

In **Table 1**, the type of maintenance is listed in the left column and the interval required for that type of maintenance is listed in the right column. For example, the interval for an **Energized Check** for Substations is 1M (or 1 month). The abbreviations used for the intervals are:

A/R = As Required
M = Month, i.e. 1M = 1 Month
Y = Year, i.e. 2Y = 2 Years

Note 1 – SCADA Pole Top reclosers are monitored continuously and do not require the monthly checks. They will be inspected for physical damage on an annual basis.

Note 2: Duty cycle is calculated based on the number and magnitude of fault interruptions. The duty cycle is calculated and monitored by all electronic controllers (except Form 3A). This is equivalent to remaining contact life.

Note 3: Use the operations count for Hydraulic controls and Form 3A controls.

Note 4: Scheduled Major Maintenance for oil filled Reclosers may be deferred if a capital replacement project has been formally established and is being implemented on a 12-year replacement plan

5.44.2 S/S Reclosers – SCADA Monitored/Controlled

See EMP Instruction 6.44 for details on performing the following maintenance activities.

5.44.2.1 Check and Inspection – Energized – Monthly

5.44.3 S/S Reclosers – Non-SCADA

ELECTRONIC

5.44.3.1 Check and Inspection – Energized – Monthly

HYDRAULIC

5.44.3.2 Check – Energized – Annually

5.44.4 Pole–Top Reclosers – SCADA

5.44.4.1 Check and Inspection – Energized – Annually

5.44.5 Pole-Top Reclosers – Non-SCADA

ELECTRONIC

5.44.5.1 Check – Energized – Every Two Months

HYDRAULIC

5.44.5.2 Check – Energized – Annually

5.44.6 Recloser – All – Major Maintenance – De-Energized (triggered by fault operations)

5.44.6.1 Vacuum Under Oil Device

5.44.7 Major Maintenance Evaluation (triggered by operations count)

5.44.8 Sectionalizers (SEC3) and Voltage Switches (VS)

General Description

The importance of following a strict maintenance program on sectionalizers cannot be over-emphasized. The nature of these devices is such that they operate primarily during times of emergency. It is their function to limit service interruptions on permanent faults to a relatively small group of customers. Failure to operate properly increases the cost and time required to restore service following an emergency and reduces the system reliability.

Sectionalizers are used with reclosers and reclosing circuit breakers to isolate permanent faults and confine outages to smaller sections of line on electric power distribution systems. They are applied on the load side of the fault-interrupting device, and can be set to trip and lockout during the first, second, or third open interval of the recloser or breaker. They are not rated to interrupt fault current; however, they can safely be closed into a fault, and can interrupt load current. Voltage Switches (VS) are those reclosers that are used as sectionalizers. Their trip settings are so high they will never trip for fault current before upstream protective devices operate. Because of the “lighter duty”

service they perform, they are maintained to the same schedule as regular sectionalizers. When a recloser is used as a VS, it shall be maintained as a recloser

Table 2 – Pole-Top Sectionalizer Maintenance Intervals

Pole-Top Sectionalizer & VS Maintenance Schedule	Sectionalizer Type	
	Electronic	**Hydraulic**
Interval-Based Maintenance		
Check – Energized – 3 Phase	4M	N/A
Check – Energized – Single Phase	1Y	1Y
IR Inspection – Energized	1Y	1Y
Major Maintenance – De-Energized	6Y or A/R	6Y or A/R

In **Table 2**, the type of maintenance is listed in the left column and the interval required for that type of maintenance is listed in the right column. For example, the interval for an IR Inspection for a **Sectionalizer** is **1Y** (or 1 Year). The abbreviations used for the intervals are:

Y = Year, i.e. 2Y = 2 Years

M = Month, i.e. 1M = 1 Month
A/R = As Required

5.44.9 Pole-Top Sectionalizers and Voltage Switches (VS)

See EMP Instruction 6.44 for details on performing the following maintenance activities.

5.44.9.1 Sectionalizer and VS – Check – Energized

5.44.9.2 Sectionalizer and Voltage Switch IR Survey Inspection

5.44.9.3 Sectionalizer and VS Major Maintenance – De-Energized

5.44.10 Failure Finding

Failures of reclosers and sectionalizers shall be documented in the equipment failure reporting system used by your region (EFRS, UPER, or Cascade, as appropriate).

5.44.11 Recloser Maintenance Basis Documentation

The maintenance activities and their schedules are based on industry Standards, manufacturer's recommendations, and Field experience.

Requirement	Basis
Check – Energized – Substation & Pole-Top Non-SCADA Electronic Reclosers – 2M **SCADA and Hydraulic Pole-Top Reclosers – 1Y** **Major Maintenance (Oil) – 12Y and (Vacuum) – N/A**	The Industry Standards recommend more frequent inspections, testing, and maintenance than our Company has followed, but they also state that operating experience should govern the maintenance plan. The sources of information we can draw on include: • IEEE Std 321-1973 "IEEE Standard Guide for the Application, Operation, and Maintenanceof Automatic Circuit Reclosers" • ANSI Std C37.61-1973. • Manufacturer's Literature • Our Operating Experience and Maintenancerecords All sources indicate that periodic inspections should be performed to look for oil leaks, check for cracked or broken bushings. Currently, Time-Directed maintenance is the standard used at NU. The intervals for Time-Directed maintenance may be affected by weather conditions.
Condition–Based Maintenance (CBM) **(Oil) – 100 Operations** **(Vacuum) 200 Fault Operations** **Major Maintenance Evaluation**	CBM for reclosers is based on: The number of operations or duty cycle. A combination of CBM and Time-Directed Maintenance is recommended by the ANSI/IEEE and the Manufacturer as it accounts for both the activity level of the recloser and the time-based requirements of the oil. Accurate and complete inspection findings, such as op counts and oil level and condition must be maintained in order to develop cost-effective maintenance plans that will keep Eversource's equipment in reliable condition. This will be performed based on discussion with the EMP Working Group.
Sectionalizers • **Check – Energized – 3 Phase – 4M** • **Check – Energized – Single Phase – All – 1Y** • **Major Maintenance – 6Y or A/R**	Sectionalizers are few in number and are scheduled to be phased out over time. The maintenance schedule will remain unchanged.

5.44.12 Appendix 1

5.44.12.1 SCADA Recloser Capabilities

The following table lists the currently used SCADA-capable Reclosers and the functions they can monitor.

SCADA Recloser Monitoring Capabilities	Siemens Advanced	Siemens Centurian	Cooper Form 6	Cooper 4c with PoleCAT
Battery Status (high/low vtg, off, etc.)	C	C	C	C
Capacitor Charge Status	C	C	N/A	N/A
Low Power Mode	C	C	N/A	N/A
Mechanism Failure	C	C	C	C
AC Power	C	C	C	N/A
System Alarm	N/A	N/A	C	N/A
RAM/ROM/EPROM Failure	N/A	N/A	C	C
Power Down Time	N/A	N/A	N/A	C

Abbreviations used in this table are:

C = Continuous

N/A = Not Applicable

5.44.13 Appendix 2 – Recloser Types & Ratings (Informational only – not intended to be an all-inclusive list of all Reclosers)

5.44.13.1 Single Phase Recloser Classifications

Single Phase Reclosers	Controller Type				Rating	
	Hydraulic		Electronic			
	Contacts in Vacuum	Contacts in Oil	Contacts in Vacuum	Contacts in Oil	Max Cont.	Int Rating Sym
Type H		X			50	1,250
4H		X			100	2,000
V4H	X				200	2,000
L		X			280	4,000
V4L	X				280	6,000
VXE15			X		400 *	8,000
D		X			500	10,000
E		X			100	2,500
4E		X			280	4,000

* 560 A. Available with Accessory

5.44.13.2 Three Phase Recloser Classifications

Three Phase Reclosers	Controller Type				Rating	
	Hydraulic		Electronic			
	Contacts in Vacuum	Contacts in Oil	Contacts in Vacuum	Contacts in Oil	Max Cont.	Int Rating Sym
Type 6H		X			100	2,000
V6H	X				200	2,000
W		X			560	10,000
WE				X	560 *	10,000
VWE			X		560 *	12,000
WVE27				X	560 *	8,000
VWVE27			X		560	12,000
NOVA27			X		630 *	12,500
WVE38X				X	560	8,000
VWVE38X			X		560 *	12,000
VSO12			X		560	12,000
NOVA38			X		630 *	12,500
Centurian 27			X		630	12,500

* 800 A. Available with Accessory

6.44 Recloser Maintenance Instructions

Before You Begin

1. Ensure that all employees are properly trained and qualified to perform this work; and all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
   - TD 211, “When to Wear FR Clothing”
   - Eversource Employee Safety & Health Handbook

Procedure

S/S Reclosers – SCADA Monitored/Controlled

Check and Inspection – Energized – Monthly

1. Make a visual inspection of the recloser:
   - Check the ground integrity
   - Check for oil leaks, if applicable.
   - Check the condition of the bushings to ensure they are not blow or badly chipped, when practical.
   - Check to ensure animal guards are present, correctly installed and in good condition.

- Check the control cable for damage from animals, vandalism, etc.

2. Record the operations counter reading.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.

CAUTION: Some recloser controls must be removed from service before you can replace their batteries. See Appendix 1 for instructions on replacing batteries for the different types of reclosers.

4. Check the date on the battery sticker and replace the batteries (as a set) based on their age as follows:
    - Form 2, 3, 3A controls – replace every 5 years
    - Form 4C controls – replace every 3 years
    - Siemens controls – replace every 3 years
    - Form 6 controls – replace every 4 years
    - Nu-Lec/Schneider Electric Recloser – replace every 3 years
    - VXE controls – replace every 6 years
    - G&W Viper Reclosers with SEL 351R/651R (SCADA) – replace every 10 years
    - G&W Viper Reclosers with SEL 351R/651R (NON-SCADA) – replace every 6 years
5. Check the battery terminal voltage.
6. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
    - A 3 – 4 volt drop is normal. A larger drop in voltage indicates the batteries are worn and due for replacement.
7. For VIPER Reclosers, check the Enable Supply Light:
    - GREEN = OK
    - OFF – Notify Supervisor
8. For VIPER Reclosers, check the Battery Problem Light:
    - OFF = OK
    - RED – Notify Supervisor
9. Check the heaters and the AC supply to the battery charger.

S/S Reclosers – Non-SCADA

ELECTRONIC

Check and Inspection – Energized

1. Record the operations counter reading.
2. Check all metering and indicating devices and inspect all control switches for normal position or electronic indication.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.
4. Make a visual inspection of the recloser:
    - Check the ground integrity.

- Check for oil leaks, if applicable.
- Check the condition of the bushings to ensure they are not blown or badly chipped, when practical.
- Check the control cable for damage from animals, vandalism, etc.
- Check to ensure animal guards are present, correctly installed and in good condition.

CAUTION: Some recloser controls must be removed from service before you can replace its batteries. See Appendix 1 for instructions on replacing batteries for the different types of recloser

5. Check the date on the battery sticker and replace the batteries (as a set) based on their age as follows:
    - Form 3A controls – replace every 5 years
    - Form 4C controls – replace every 3 years
    - Siemens controls – replace every 3 years
    - Form 6 Controls – replace every 4 years
    - Nu-Lec/Schneider Electric Recloser – replace every 3 years VXE controls – replace every year
    - G&W Viper Reclosers with SEL 351R/651R (SCADA) – replace every 10 years
    - G&W Viper Reclosers with SEL 351/651R (NON-SCADA) – replace every 6 years
6. Check the battery terminal voltage.
7. For VIPER Reclosers, check the Enable Supply Light:
    - GREEN = OK
    - OFF – Notify Supervisor
8. For VIPER Reclosers, check the Battery Problem Light:
    - OFF = OK
    - RED – Notify Supervisor
9. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
    - A 3 – 4 volt drop is normal. A larger drop in voltage indicates the batteries are worn and due for replacement.
10. Check the heaters and the AC supply to the battery charger.

S/S Reclosers – Non-SCADA

HYDRAULIC

Check – Energized

1. Make a visual inspection of the recloser.
2. Record the operations counter reading.
3. Check for the following:
    - Ensure there are no oil leaks.
    - Check to ensure animal guards are present, correctly installed and in good condition.
    - Ensure that lightning arresters are present and in good condition.
    - Ensure the Trip / Close lever is in its normal position.

Pole–Top Reclosers – SCADA

Check and Inspection – <u>Energized</u>

1. Make a visual inspection of the recloser:
    - Check the ground integrity.
    - Check to ensure lightning arresters are present and in good condition.
    - Check for oil leaks, if applicable.
    - Check the condition of the bushings to ensure they are not blown or badly chipped, when practical.
    - Check the control cable for damage from animals, vandalism, etc.
    - Check to ensure animal guards are present, correctly installed and in good condition.
2. Perform touch potential testing on all controls or components that may be accessible to the public.
3. Record the counter reading.
4. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.

CAUTION: Some recloser controls must be removed from service before you can replace its batteries. See Appendix 1 for instructions on replacing batteries for the different types of reclosers.

5. Check the date on the battery sticker and replace the batteries (as a set) based on their age as follows: (Instructions for changing batteries are at the end of this section.)
    - Form 3A controls - replace every 5 years
    - Form 4C controls - replace every 3 years
    - Siemens controls - replace every 3 years
    - Form 6 controls - replace every 4 years
    - Nu-Lec/Schneider Electric Recloser – replace every 3 years VXE controls – replace every 6 years.
    - G&W Viper Reclosers with SEL 351R/651R (SCADA) – replace every 10 years.

- G&W Viper Reclosers with SEL 351R/651R (NON-SCADA) – replace every 6 years.

6. Check the battery terminal voltage.
7. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
8. For VIPER Reclosers, check the Enable Supply Light:
   - GREEN = OK
   - OFF – Notify Supervisor
9. For VIPER Reclosers, check the Battery Problem Light:
   - OFF = OK
   - RED – Notify Supervisor
10. Check the heaters and the AC supply to battery charger.

Pole-Top Reclosers – Non-SCADA

ELECTRONIC

Check - <u>Energized</u>

1. Record the operations counter reading.
2. Check all metering and indicating devices and inspect all control switches for normal position or electronic indication.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.
4. Make a visual inspection of the recloser:
   - Check the ground integrity.
   - Check to ensure lightning arresters are present and in good condition.
   - Check for oil leaks, if applicable.
   - Check the condition of the bushings to ensure they are not blown or badly chipped, when practical.
   - Check the control cable for damage from animals, vandalism, etc.
   - Check to ensure animal guards are present, correctly installed and in good condition.

CAUTION: Some recloser controls must be removed from service before you can replace its batteries. See Appendix 1 for instructions on replacing batteries for the different types of reclosers.

5. Perform touch potential testing on all controls or components that may be accessible to the public.
6. Check the date on the battery sticker and replace the batteries (as a set) based on their age as follows:

- Form 3A controls – replace every 5 years
- Form 4C controls – replace every 3 years
- Siemens controls – replace every 3 years
- Form 6 controls – replace every 4 years
- Scweitzer SEL-651R controls replace every 3 years.
- Nu-Lec/Schneider Electric recloser – replace every 3 years. VXE controls – replace every 6 years.
- G&W viper Reclosers with SEL 351R/651R (SCADA) – replace every 10 years.
- G&W Viper Reclosers with SEL 351R/651R (NON-SCADA) – replace every 6 years.

7. Check the battery terminal voltage.
8. For VIPER Reclosers, check the Enable Supply Light:
   - GREEN = OK
   - OFF – Notify Supervisor
9. For VIPER Reclosers, check the Battery Problem Light:
   - OFF = OK
   - RED – Notify Supervisor
10. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
11. Check the heaters and the AC supply to battery charger.

Pole-Top Reclosers – Non-SCADA

HYDRAULIC

Check – <u>Energized</u> – Annually

1. Make a visual inspection of the recloser.
2. Record the operations counter reading.
3. Perform touch potential testing on all controls or components that may be accessible to the public.
4. Ensure that all metering and indicating devices are in their normal positions.

Recloser – All – Major Maintenance – <u>De-Energized</u>

While most Major Maintenance for reclosers is performed at a maintenance shop, some is performed on-site. Perform the following steps:

1. Remove the unit from service.
2. Measure contact resistance to provide an indication of contact condition as well as loose current carrying parts. Use of a micro-ohmmeter is the recommended method.
3. Perform an insulation test (utilizing an insulation tester), phase-to-

phase, and phase-to-ground.

4. Inspect and dress the main and control contacts, if necessary.
5. Perform visual inspections on the interrupting chambers.
6. Check clearance and adjust them to manufacturer's specifications for that recloser model.
7. Check all electrical and mechanical connections for correct tightness.
8. Thoroughly clean all internal mechanisms and tanks, and remove all carbon. Check for traces of tracking on all insulating parts and moisture absorption of the bottom of the tank liner.
9. Check all gaskets.
    - Replace the main tank gasket, as necessary.
    - Replace the tank liners, as necessary.
    - Replace bushing gaskets, as necessary.
10. Check and adjust the component parts of the operating mechanism, if required.
11. Use an electronic control unit to operate the recloser before it goes back into service.
12. Thoroughly clean the exterior of the recloser.
13. Inspect the exterior of the recloser for
    - Cracked, chipped, or broken bushings. Replace as necessary.
    - Paint scratches or other mechanical damage. Repaint as necessary to prevent corrosion.
14. Refer to the Manufacturer's manual for maintenance requirements specific to the recloser model you are servicing.
15. Perform a dielectric test of the oil.
16. Filter the oil and perform a second dielectric test to act as the as-left reading.
17. Change lightning arresters, as required.
18. Verify the recloser and its lightning arrester are the correct voltage for the planned installation.
19. For hydraulically controlled reclosers, operate the recloser manually to lockout, verifying minimum pickup and time current characteristics.

Vacuum Under Oil Device
(Perform these steps and appropriate work activities outlined under Major Maintenance.)

1. Perform an AC high potential test on each interrupter in accordance with manufacturer's instructions or NU specifications. Perform this test carefully as it provides the best means for verifying the condition of the interrupter.
2. If the manufacturer has provided a scribe mark for monitoring contact erosion, check the reference dimension to measure wear.

Solid Dielectric Vacuum Recloser
(Siemens and Cooper NOVA Reclosers and G&W Viper)

No user maintenance of the recloser mechanism is required. The recloser should be considered for refurbishment or retired if the mechanical duty or breaking duty on any phase is less than (5%). This can be determined this by checking the Operator Control Panel. Further details on maintenance on the recloser and control cubicle are located in the Siemens or Cooper instruction book.

POLE-TOP SECTIONALIZERS AND VOLTAGE SWITCHES (VS)

Sectionalizer and VS – Check – Energized

1. Perform a visual inspection and record the operations counter.
2. Perform touch potential testing on all controls or components that may be accessible to the public.

Sectionalizer and Voltage Switch IR Survey Inspection

1. Perform an Infrared test during a Distribution IR Survey or as required.

Sectionalizer and VS Major Maintenance – De-Energized

Note: Sectionalizers that have problems may be replaced and taken back to the shop for inspection/maintenance.

1. Perform a power factor test to measure contact resistance to provide an indication of contact condition as well as loose carrying parts.
2. Perform an insulation resistance test (utilizing a micro-ohm meter), phase-to phase, and phase-to-ground.
3. Test for proper operation on the Sectionalizer.
4. Inspect and dress the main and control contacts, if necessary.
5. Inspect interrupting chambers for both mechanical and electrical conditions.
6. Check all electrical and mechanical connections for tightness.
7. Thoroughly clean and remove carbon from the internal mechanism and tanks.
8. Check for traces of tracking on all insulating parts and moisture absorption of the bottom of the tank liner.
9. Check and adjust the component parts of the operating mechanism, if required.
10. Check all gaskets.
11. Ensure the tap wires are properly tightened.
12. Paint, where necessary.
13. Test Oil (Color and dielectric strength); filter and/or replace as necessary.

Appendix 1 – Recloser Battery Replacement

Cooper Form 6 Controls

IMPORTANT: Disconnect switches for AC sensing and power connections are necessary to isolate the Form 6 control for testing and servicing.

1. Enable GND TRIP BLOCKED to allow for ground trip to be disabled when reenergized.
    a) Press the CHANGE button on the Operator Panel to enter the CHANGE mode.
    b) Press the GND TRIP BLOCKED button within ten seconds after entering the CHANGE mode.

NOTE: If the GND TRIP BLOCKED button is not pressed within ten seconds, the function is not activated.

2. Disconnect the old battery and replace it with a new one.

Siemens

CAUTION

The batteries supplied with the Recloser can deliver high discharge currents. ***This may result in personal injury or damage to equipment.*** Do not reverse polarity when making battery connections. Immediately replace any frayed leads or damaged connectors.

1. Turn off the battery circuit breaker.
2. Unplug the batteries and replace them with new ones.
3. Confirm the battery polarity is correct.
4. Turn on the battery circuit breaker.
5. Verify that “Battery Normal Status” displays.

Appendix 1 – Battery Replacement

Cooper Form 2, Form 3 and Form 3A Controls

Reclosers

COOPER Power Systems

Type ME Electronic Control
KA450ME Replacement Battery
Installation Instructions

Service Information
S280-75-35

Applicable to Form 2, Form 3, and all Form 3A Controls.

DESCRIPTION

The Kyle® Type ME Electronic control may have been originally equipped with either a Gould, General Electric or Gates Energy Products battery. These batteries are functionally interchangeable and use the same mounting hardware. However, the General Electric and the Gates Energy Products batteries are slightly shorter than the Gould battery and they have different mounting dimensions.

Figure 2 shows the location of the battery-mounting clips, and bottom bracket for each battery. Note that all batteries are installed with the leads at the top.



Figure 1.
Type ME control battery.

SAFETY FOR LIFE

Kyle Distribution Switchgear products meet or exceed all applicable industry standards relating to product safety. We actively promote safe practices in the use and maintenance of our products through our service literature, instructional training programs, and the continuous efforts of all Kyle employees involved in product design, manufacture, marketing, and service.

We strongly urge that you always follow all locally approved safety procedures and safety instructions when working around high voltage lines and equipment and support our "Safety For Life" mission.

SAFETY INFORMATION

Following is important safety information. For safe installation and operation of this equipment, be sure to read and understand all cautions and warnings.

Safety Instructions

Following are general caution and warning statements that apply to this equipment. Additional statements, related to specific tasks and procedures, are located throughout the manual.

Hazard Statement Definitions

This manual contains two types of hazard statements:

WARNING: Refers to hazards or unsafe practices which could result in severe personal injury, or death, and equipment damage.

CAUTION: Refers to hazards or unsafe practices which could result in damage to equipment or in personal injury.

CAUTION: Before installing, operating, maintaining, or testing this equipment, carefully read and understand the contents of this manual. Improper operation, handling or maintenance can result in death, severe personal injury, and equipment damage. G101.0

CAUTION: Recloser misoperation. The control must be removed from service prior to performing any maintenance, testing, or programming changes. Failure to comply can result in mis-operation (unintentional operation) of the recloser. T216.2

WARNING: This equipment is not intended to protect human life. Follow all locally approved procedures and safety practices when installing or operating this equipment. Failure to comply can result in death, severe personal injury and equipment damage. G102.1

WARNING: Hazardous voltage. Contact with high voltage will cause death or severe personal injury. Follow all locally approved safety procedures when working around high voltage lines and equipment. G103.2

Appendix 1 – Battery Replacement
Cooper Form 2, Form 3 and Form 3A Controls

Type ME Electronic Control Replacement Battery Installation Instructions

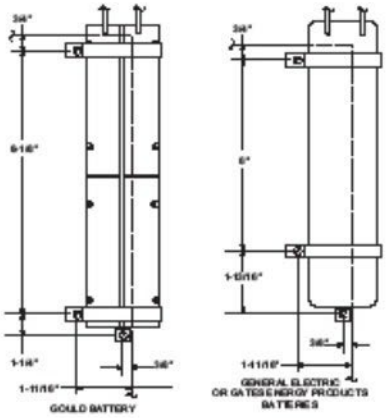


Figure 2.
Mounting dimensions for control battery.

TO REMOVE THE CONTROL FROM SERVICE

1. Place the Ground Trip Switch to BLOCK.
2. Disconnect the recloser interconnecting cable at the receptacle on the bottom of the control cabinet.
3. Operate the Manual Control Switch to OPEN to disconnect the control battery.

CAUTION: Recloser misoperation. The control must be removed from service prior to performing any maintenance, testing, or programming changes. Failure to comply can result in mis-operation (unintentional operation) of the recloser. T316.2

MOUNTING

Holes for either battery are drilled and tapped in the back panel with serial number 15000 and above. Controls below serial number 15000 have mounting holes for the Gould battery only. When the Gates Energy Products battery is being installed as a replacement, two holes must be drilled and tapped into the back panel to relocate the existing lower mounting clip and the bottom bracket. A drilling layout is shown in Figure 3.

CAUTION: Equipment damage. Drill mounting holes through back panel only. Do not drill through cabinet wall. Remove all metal fragments from inside control cabinet. Failure to comply can result in control and recloser misoperation, equipment damage, and personal injury. T266.0

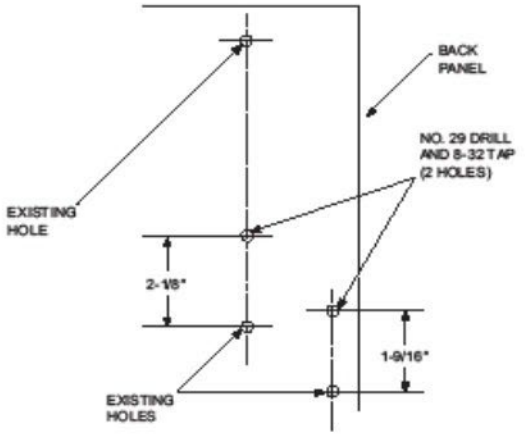


Figure 3.
Drilling layout for mounting battery on controls below serial number 15000.

TO RETURN THE CONTROL TO SERVICE

1. Make sure the Ground Trip is in BLOCK.
2. Check that the battery is connected and all control settings and plugs are programmed.
3. Operate the Manual Control Switch to CLOSE and make sure the control is in the home position; verify by placing the Test switch to LOCKOUT TEST; the Lockout Indicator lamp should not light.
4. Reconnect the recloser interconnecting cable to the receptacle on the bottom of the control cabinet.
5. Place the Ground Trip switch to NORMAL.

SAFETY FOR LIFE

COOPER Power Systems

©2001 Cooper Power Systems, Inc.
Kyle® is a registered trademark of Cooper Industries, Inc.

P.O. Box 1640
Waukesha, WI 53187
www.cooperpower.com

KA2048-228

Printed on Recycled Paper

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

COOPER Power Systems

Reclosers

Form 4C Microprocessor-Based Recloser Control Standard and Automation Power Supply Installation and Operation Instructions

Service Information
S280-77-9

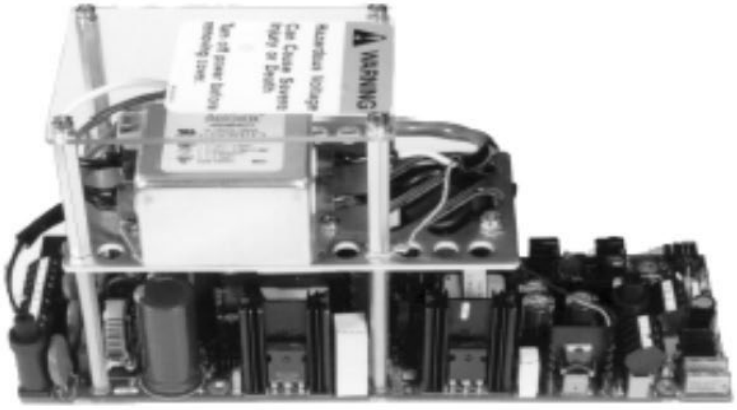


Figure 1.
Kyle® Form 4C Control Automation Power Supply KME4-441-7001.

Contents

Safety Information 2
Product Information 3
Introduction 3
Acceptance and Initial Inspection 3
Handling and Storage 3
Description 3
Operation 4
Specifications 4
Installation Procedure 6
To Remove Control From Service 6
Removal of Existing Power Supply 6
Installation of New Power Supply 7
Testing and Troubleshooting 9
Verification of Operation 9
Control Fails to Power Up 9
Isolated DC Outputs Fail to Operate 10
Returning Control to Service 10
Maintenance Information 10
Parts List 11

TABLE 1
Ordering Information

Description	Catalog Number
Standard Power Supply with Block of Close wiring	KME4-440-7001
Automation Power Supply with 12 and 24 Vdc outputs; Block of Close wiring	KME4-441-7001

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

SAFETY FOR LIFE

Cooper Power Systems products meet or exceed all applicable industry standards relating to product safety. We actively promote safe practices in the use and maintenance of our products through our service literature, instructional training programs, and the continuous efforts of all Cooper Power Systems employees involved in product design, manufacture, marketing, and service.

We strongly urge that you always follow all locally approved safety procedures and safety instructions when working around high voltage lines and equipment and support our "Safety For Life" mission.

SAFETY INFORMATION

The instructions in this manual are not intended as a substitute for proper training or adequate experience in the safe operation of the equipment described. Only competent technicians who are familiar with this equipment should install, operate, and service it.

A competent technician has these qualifications:

- *Is thoroughly familiar with these instructions.*
- *Is trained in industry-accepted high- and low-voltage safe operating practices and procedures.*
- *Is trained and authorized to energize, de-energize, clear, and ground power distribution equipment.*
- *Is trained in the care and use of protective equipment such as flash clothing, safety glasses, face shield, hard hat, rubber gloves, hotstick, etc.*

Following is important safety information. For safe installation and operation of this equipment, be sure to read and understand all cautions and warnings.

Hazard Statement Definitions

This manual may contain four types of hazard statements:

DANGER: Indicates an imminently hazardous situation which, if not avoided, will result in death or serious injury.

WARNING: Indicates a potentially hazardous situation which, if not avoided, could result in death or serious injury.

CAUTION: Indicates a potentially hazardous situation which, if not avoided, may result in minor or moderate injury.

CAUTION: Indicates a potentially hazardous situation which, if not avoided, may result in equipment damage only.

Safety Instructions

Following are general caution and warning statements that apply to this equipment. Additional statements, related to specific tasks and procedures, are located throughout the manual.

DANGER: Hazardous voltage. Contact with hazardous voltage will cause death or severe personal injury. Follow all locally approved safety procedures when working around high and low voltage lines and equipment.

WARNING: Before installing, operating, maintaining, or testing this equipment, carefully read and understand the contents of this manual. Improper operation, handling or maintenance can result in death, severe personal injury, and equipment damage.

WARNING: This equipment is not intended to protect human life. Follow all locally approved procedures and safety practices when installing or operating this equipment. Failure to comply can result in death, severe personal injury, and equipment damage.

WARNING: Power distribution equipment must be properly selected for the intended application. It must be installed and serviced by competent personnel who have been trained and understand proper safety procedures. These instructions are written for such personnel and are not a substitute for adequate training and experience in safety procedures. Failure to properly select, install, or maintain power distribution equipment can result in death, severe personal injury, and equipment damage.

Cooper Form 4C Power Supply Replacement

PRODUCT INFORMATION

Introduction

Service Information S280-77-9 provides field installation and operation instructions for both the Standard and Automation Power Supplies used in the Kyle Form 4C microprocessor-based recloser control. Before installing and operating this device, carefully read and understand the contents of this manual.

Read This Manual First

Read and understand the contents of this manual and follow all locally approved procedures and safety practices before installing or operating this equipment.

Additional Information

These instructions cannot cover all details or variations in the equipment, procedures, or process described, nor to provide directions for meeting every possible contingency during installation, operation, or maintenance. For additional information, please contact your Cooper Power Systems representative.

Acceptance and Initial Inspection

Each Form 4C power supply is tested and inspected at the factory. It is carefully calibrated, adjusted and in good condition when accepted by the carrier for shipment.

Upon receipt, inspect the carton for signs of damage. Unpack the power supply and inspect it thoroughly for damage incurred during shipment. If damage is discovered, file a claim with the carrier immediately.

Handling and Storage

Be careful during handling and storage of the power supply to minimize the possibility of damage. If it is to be stored for any length of time prior to installation, provide a clean, dry storage area.

IMPORTANT: The power supply assembly should be stored in a static-proof bag.

ANSI Standards

Kyle reclosers are designed and tested in accordance with ANSI standards C37.60 and C37.85 and ANSI guideline C37.61.

Quality Standards

ISO 9001:2000-certified quality management system

Description

The Kyle Form 4C Standard Power Supply and Automation Power Supply are designed for easy integration into existing Form 4C controls. The standard Power Supply provides power for the Form 4C central processing unit and cabinet heater, and maintains optimum charge levels of back-up batteries.

The Automation Power Supply provides the same basic functions with additional isolated 12 Vdc and 24 Vdc supply circuits, enabling powering of radio communication units, RTUs and other accessories.

The Standard and Automation Power Supply kits include the power supply board and an input filter with block of close wiring. The Automation Power supply with isolated 12 and 24 Vdc outputs includes a thermally controlled fan.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

OPERATION

The Form 4C Standard and Automation Power Supplies utilize an off-line switcher for the primary stage, generating a high-voltage bus, and a second stage switcher for the isolated control power feature of the Automation Power Supply. The ac voltage monitor circuit is completely contained on the power supply board, along with the CPU interface drivers. The off-line switcher generates a high-voltage dc bus that is proportional to line voltage. Selector switch SW2 (refer to Figure 6) establishes the threshold voltage used to monitor and detect the loss of ac line voltage. The threshold reference is approximately 80% of the selected nominal voltage. Selectable values of 110/220, 120/240 and 127/254 Vac enable monitoring of local values common to most domestic and international nominal voltages.

The Form 4C Standard and Automation Power Supplies utilize an advanced programmable integrated chip to oversee the battery charging and monitoring circuitry. Battery charging is based upon a temperature-compensated float voltage charge curve optimized for the specific battery normally included with all Form 4C Controls.

Battery life is maximized by the use of a programmable integrated chip which tailors the charge rate to the minimum level required to charge and maintain the battery at full charge. The charge rate is continuously adjusted over the entire operating temperature range of –40°C to +65°C to optimize battery life based upon charge acceptance.

An automatic self-test feature will warn of a no battery or dead battery condition. The operation of the self-test feature is dependent upon any of several circumstances that can occur in the battery circuit. Upon control power-up, the power supply will report a battery low/voltage malfunction and repeat the test every minute until the test recognizes a "good" battery. Upon connecting a battery to the control or replacing the bad battery with a good battery, the supply will repeat the self-test approximately every 12 hours.

If a missing or bad battery is detected during the normal 12-hour test cycle, a battery malfunction indication will be initiated. The circuitry will then recheck the battery every minute thereafter, until a good battery is detected.

TABLE 2
General Specifications

	Standard Power Supply	Automation Power Supply
Input Voltage	120/240 Vac@50/60 Hz	120/240 Vac@50/60 Hz
Input Power	2 A@120 Vac, 1 A@240 Vac	2A@120Vac, 1 A@240 Vac
Isolated Vdc Outputs	N/A	12Vdc@2.9A, 24 Vdc@250 mA
Operating Temperature Range,°C	-40° to +65°	-40° to +65°

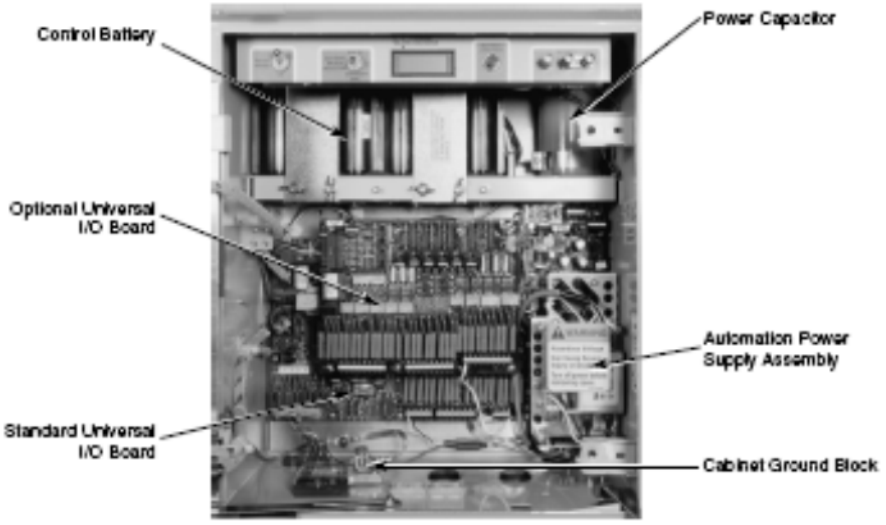
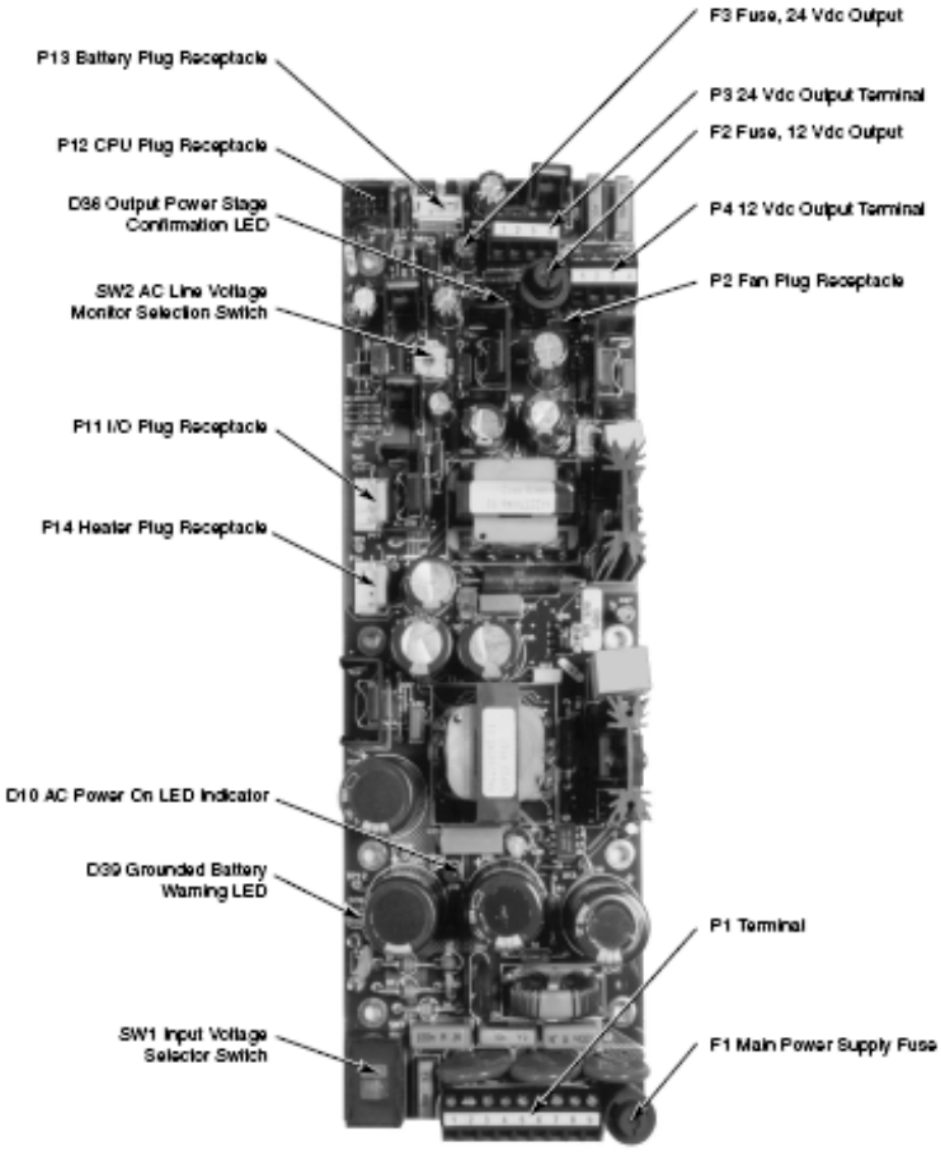


Figure 2.
Automation Power Supply Installed in Form 4C control.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement



Note: Items P2, P3, P4, F2,F3 and D86 are not present on Standard Power Supply KME4-440-7001.

Figure 3.
Automation Power Supply KME4-441-7001 Circuit Board.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

INSTALLATION PROCEDURE

IMPORTANT: The Form 4C control must be removed from service and transported to a clean and suitably equipped service center prior to installing the new power supply.

The following procedure should be used to install the Form 4C power supply. For additional information, refer to *Service Information S280-77-1 Form 4C Microprocessor-Based Recloser Control Installation and Operation Instructions.*

DANGER: Hazardous voltage. Contact with hazardous voltage will cause death or severe personal injury. Follow all locally approved safety procedures when working around high voltage lines and equipment.

CAUTION: Recloser misoperation. The control must be removed from service prior to performing any maintenance, testing, or programming changes. Failure to comply can result in misoperation (unintentional operation) of the recloser.

To Remove Control From Service

The following steps must be taken to remove the control from service and prevent possible recloser misoperation.

1. Switch Ground Trip Block switch to BLOCK.
2. Disconnect control cable from the control.
3. De-energize ac power from the control.
4. Unplug the control battery.

Removal of Existing Power Supply

CAUTION: Control damage. De-energize both ac and dc power prior to removing or installing any internal connections or circuit boards in the control. Failure to comply can result in damage to the control.

CAUTION: Equipment damage. Always wear a grounding wrist strap to control static electricity before handling circuit boards. Failure to use this strap may result in circuit board damage.

1. Ground the control cabinet using the external ground terminal lug located at the base of the Form 4C control cabinet.
2. Disconnect control supply voltage leads at terminal P1.
3. Disconnect battery terminal supply plug at receptacle P13.
4. Disconnect CPU board terminal plug at receptacle P12.
5. Disconnect heater terminal plug at receptacle P14.
6. Remove and discard "Block of Close" wiring between power supply board and Standard Universal I/O board terminals 1 and 2 if so equipped.
7. Remove and discard old power supply board and nylon spacers.
8. Remove and discard the spare fuse box and contents located on the inside of the cabinet.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

Installation of New Power Supply

1. Place polypropylene insulator pad over aluminum spacers against back panel. See Figure 4, 5, and 6 for steps 1 through 12.
2. Observing anti-static precautions, remove the new power supply board from its packaging and secure directly to the existing aluminum spacers at the three positions shown using three #8-32 x .37" screws.
3. Thread a 2.75" long spacer and a #8 external tooth lock washer into five open positions on the power supply board. Connect ground braid to lower left spacer and adjacent fixed panel mounting screw (refer to Figure 6). The right middle position is secured by a #8-32 x .37" screw.
4. Connect terminal plug, part of the input power plate wire assembly to "P1" receptacle on bottom of power supply.
5. Mount input power plate wire assembly to long spacers using the 2.0" short threaded spacers, at four corner positions. The left middle position is secured by a #8-32 x .37" screw. Connect the drain lead of the filter cable under the upper right spacer as shown in Figures 5 and 6.
6. Connect the green ground lead from "FL" filter to cabinet ground as shown in Figure 6. Connect the two twisted leads from power supply board terminal P1 to Standard Universal I/O board terminal STB: white lead from STB-1 to P1-4, black lead from STB-2 to P1-6. For Automation Power Supply unit, connect input power assembly fan leads to terminal receptacle P2.
7. Reconnect heater leads at terminal receptacle P14.
8. Reconnect I/O leads at terminal receptacle P11.
9. Reconnect CPU leads at terminal receptacle P12.
10. Reconnect battery leads at terminal receptacle P13.
11. Place the input power decal on a clear area inside the cabinet adjacent to power supply as shown in Figure 5. On Automation Power Supply unit, place additional dc output connection decal above and adjacent to input power decal.
12. Mount the spare fuse storage box/s to the inside bottom of control console where space permits. See Figure 5.
13. Set power supply input voltage selector switch SW1 to either 115 or 230 Vac position. See Figure 6 for steps 13 through 15.
14. Set line voltage monitoring switch SW-2 to match local line voltage levels.

    Note: Selector switch SW2 establishes the threshold voltage used to monitor and detect the loss of AC line voltage.

15. Connect the ac voltage input leads to terminal TB per the ac input decal, and secure the clear acrylic safety shield on the four short spacers with four #8-32 x .37 screws.

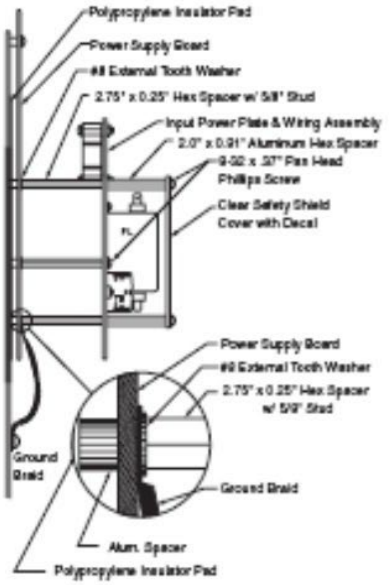


Figure 4.
Assembly Details of Power Supply Board, Input Power Plate and Safety Shield.

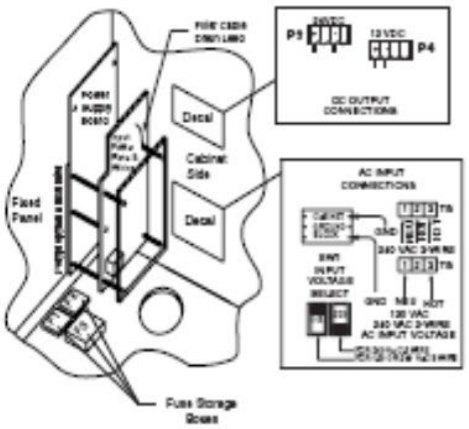


Figure 5.
Placement of Connection Decals and Fuse Storage Boxes KME4-441-7001.

IMPORTANT: Safety shield cover must be in place when Form 4C control is energized.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

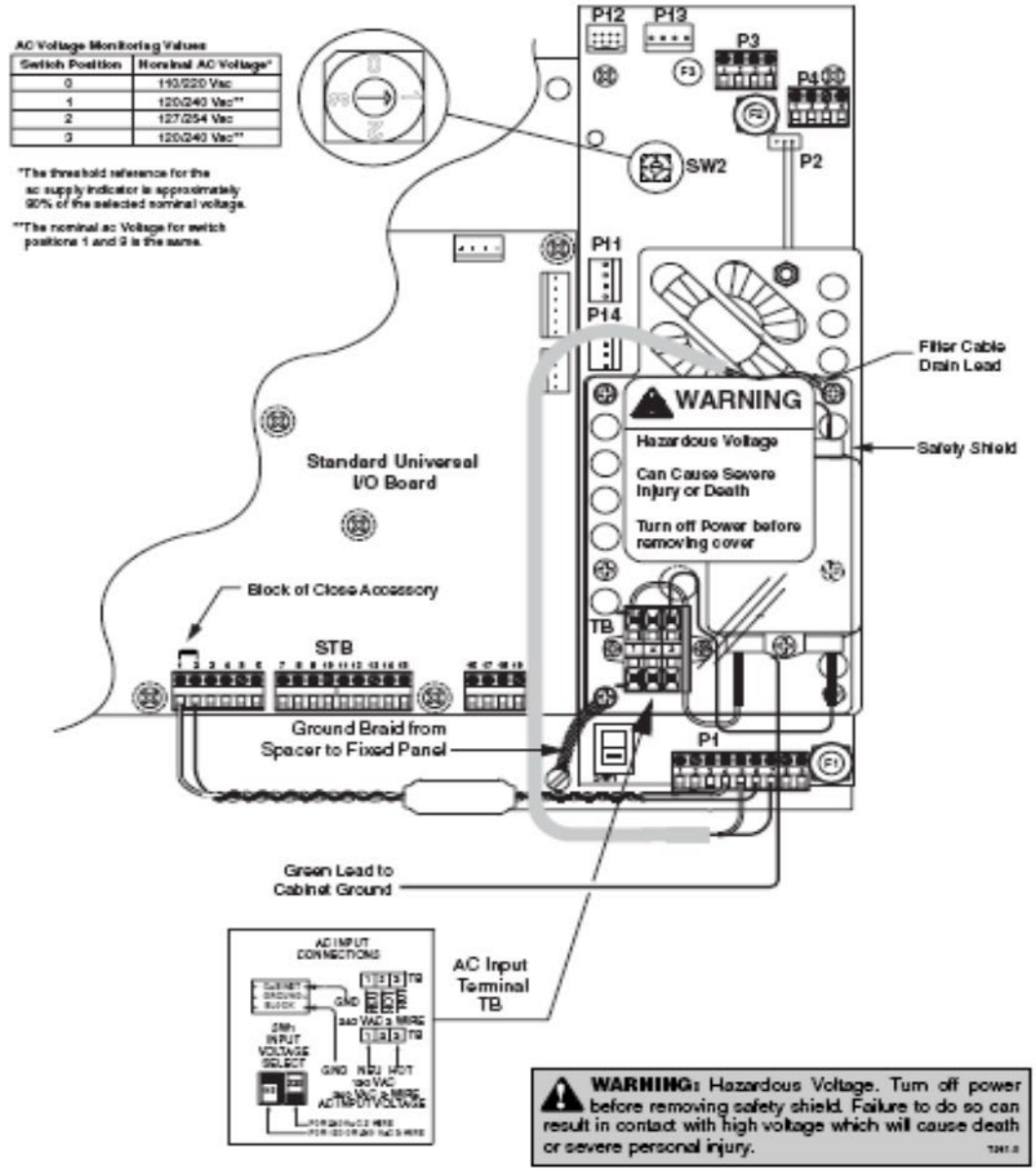


Figure 6.
Form 4C Power Supply Customer Connections Diagram KME4-441-7001.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

TESTING AND TROUBLESHOOTING

CAUTION: Recloser misoperation. The control must be removed from service prior to performing any maintenance, testing, or programming changes. Failure to comply can result in misoperation (unintentional operation) of the recloser.

Verification of Operation

1. Energize ac power to the control. Verify that control powers up on ac. Red ac power-on LED indicator D10 on power supply board should illuminate.
2. De-energize ac input and verify control operates off of battery only. Observation of LCD output on either Recloser Open, Recloser Closed, or Control Lockout LCD indicators located on front control panel confirms battery operation.

   Note: Red ac power-on LED indicator on power supply board will not illuminate during dc operation.
3. Using a digital multimeter, verify dc output voltage of Automation Power Supply by checking terminals P3 and P4 for output of 24 Vdc and 12 Vdc respectively per labels on side of cabinet.

Note: Fan is thermally controlled and will not necessarily operate during testing procedure.

Control Fails To Power-Up

If the control fails to power-up during the initial verification of operation test, the following troubleshooting procedure will aid in determining the source of malfunction.

CAUTION: Equipment damage. Always wear a grounding wrist strap to control static electricity before handling circuit boards. Failure to use this strap may result in circuit board damage.

CAUTION: Control damage. De-energize both ac and dc power prior to removing or installing any internal connections or circuit boards in the control. Failure to comply can result in damage to the control.

WARNING: Hazardous voltage. Turn off power before removing safety shield. Failure to do so can result in contact with high voltage which will cause death or severe personal injury.

1. Replace the main power supply 5A fuse at F1(see Figure 6).
2. If Form 4C control still fails to power-up, either the ac power supply or the control front panel is defective. To isolate the problem, check operating power to the control. A voltage test procedure is used to determine which circuit assembly is faulty.

Terminal P11, located on the ac supply board (see Figure 6), contains three test points to verify the status of the board. The proper voltage across each of the three test points of P11 is as follows:

Pin 1 (Black wire)	Zero (battery ground point)
Pin 3 (Blue wire)	> 25.0 Vdc
Pin 4 (Red wire)	24.0 Vdc

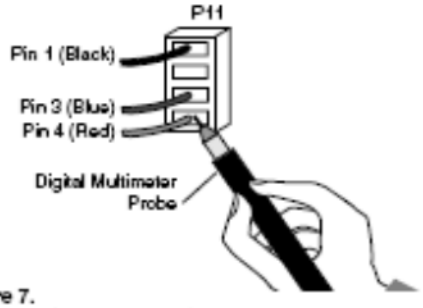


Figure 7.
Testing voltage of P11 on the ac power supply board.

Follow the procedure to test the voltages of P11 test points:

Pin 1

1. Using a digital multimeter, place the ground probe against the aluminum plate of the back panel of the control.

Note: Keep the ground probe in contact with the aluminum plate for all three dc voltage measurements.

2. Place the positive probe into the Pin 1 location. See Figure 7.

If Pin 1 does not read zero, the ac supply board is defective and must be replaced.

Pin 3

3. Disconnect the control battery.
4. With the ground probe against the aluminum plate, place the positive probe into the Pin 3 location.

If Pin 3 does not measure greater than 25.0 Vdc, the ac supply board is defective and must be replaced.

Pin 4

The computer and display boards, located in the control front panel, receive dc power from Pin 4 of terminal P11 (Red wire). A short circuit in the computer board can cause Pin 4 to read a voltage lower than 24 Vdc.

If Pin 4 of P11 is not 24 Vdc, with the control battery disconnected, follow the instructions below:

5. Disconnect terminal P12 located at the top of the ac supply board. See Figure 6.
6. Reconnect ac power.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

7. Using a digital multimeter, place the ground probe against the aluminum plate of the back panel of the control.
8. Place the positive probe into the Pin 4 location of P11. See Figure 7.

If the power supply measures 24 Vdc with terminal P12 disconnected, the computer board is defective and the control front panel must be replaced.

If the power supply is less than 24 Vdc with terminal P12 disconnected, the power supply board is defective and must be replaced.

Isolated DC Outputs Fail to Operate

(KME4-441-7001 Automation Units Only)

CAUTION: Recloser misoperation. The control must be removed from service prior to performing any maintenance, testing, or programming changes. Failure to comply can result in misoperation (unintentional operation) of the recloser.

CAUTION: Equipment damage. Always wear a grounding wrist strap to control static electricity before handling circuit boards. Failure to use this strap may result in circuit board damage.

CAUTION: Control damage. De-energize both ac and dc power prior to removing or installing any internal connections or circuit boards in the control. Failure to comply can result in damage to the control.

WARNING: Hazardous voltage. Turn off power before removing safety shield. Failure to do so can result in contact with high voltage which will cause death or severe personal injury.

1. Energize ac power to the control. Verify that control powers up on ac. Red ac power-on LED indicator D10 on power supply board should illuminate. Refer to Figure 6 for steps 1 through 4.
2. Using a digital multimeter, verify dc output voltage of Automation power supplies by checking terminals P3 and P4 for output of 24 Vdc and 12 Vdc respectively per labels on side of cabinet.
3. If no power is detected at 24 Vdc output terminal P3, replace fuse at F3. The absence of voltage after replacing fuse indicates the power supply board is defective and must be replaced.
4. If no power is detected at 12 Vdc output terminal P4, replace fuse at F2. The absence of voltage after replacing fuse indicates the power supply board is defective and must be replaced.

RETURNING CONTROL TO SERVICE

Prior to returning the control to service, the following procedure must be completed and verified:

1. Power supply ac input voltage selector switch SW1 set to either 115 or 230 Vac, matching the input voltage level supplied to the power supply.
2. Power supply selector switch SW2 set to ac line voltage monitoring level, matching local levels.
3. Plug in the control battery.

   Note: The Form 4C control will not power up until ac power is applied.
4. Apply ac power to the control.
5. Reconnect the control cable to the control.
6. Switch Ground Trip Block switch to NORMAL.
7. Reset the control clock after ac power has been re-applied. (Refer to the Setting The Control Clock section of *Service Information S280-77-4, Form 4C Microprocessor-Based Recloser Control Programming Guide.*)

MAINTENANCE

Kyle Form 4C Standard and Automation Power Supplies have no user-serviceable components. As a result, no maintenance or servicing of power supplies should be attempted in the field. Power supplies under warranty should be returned to Cooper Power Systems for exchange. Non-warranty power supplies should be discarded and replaced with a new Kyle manufactured power supply only.

Factory-Authorized Service Centers

Factory-authorized service centers are located throughout the continental United States to provide maintenance, repair, and testing services for Kyle Products. For further information, contact your Cooper Power Systems sales representative.

Factory Maintenance Classes

The factory Service Department offers specialized Kyle product maintenance training classes. These classes, taught by experienced service technicians, are held at the factory's in-house training facility. These courses provide training and factory-recommended procedures for the routine maintenance, troubleshooting, repair, and testing of Kyle products. It is recommended that all personnel who service and maintain Kyle Distribution Switchgear attend the appropriate classes. For additional information, contact your Cooper Power Systems representative.

Appendix 1 – Battery Replacement
Cooper Form 4C Power Supply Replacement

STANDARD/AUTOMATION POWER SUPPLY PARTS LIST

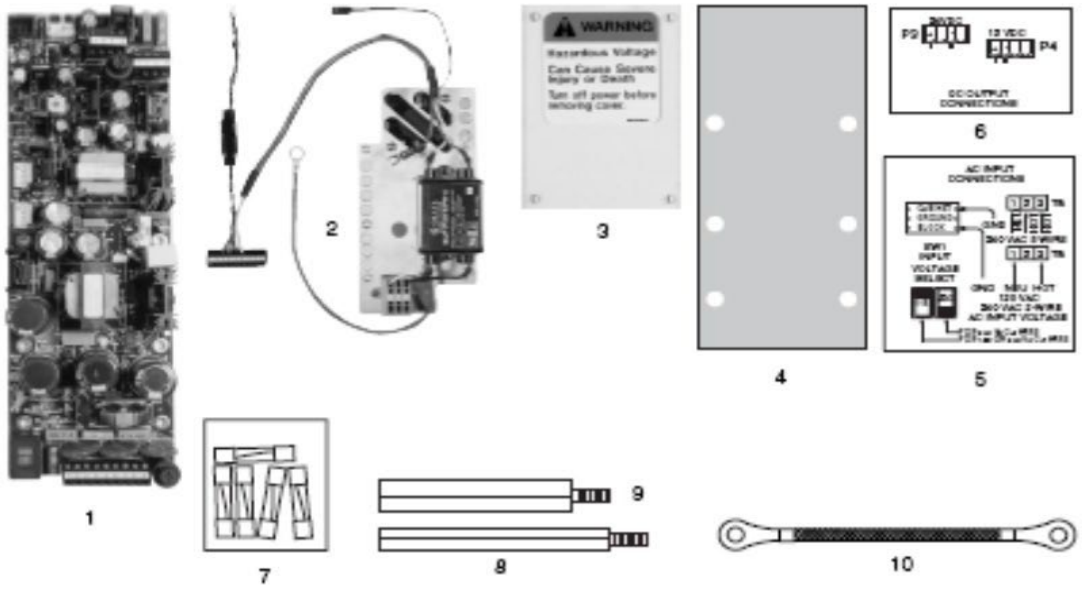


Figure 8.
Form 4C Standard/Automation Power Supply Kit Parts.

TABLE 3
Kit Parts

Item	Description	KME4-440-7001	KME4-441-7001
1	Power Supply Board	1	1
2	Input Power Plate w/Block of Close Wiring	1	1
3	Safety Shield w/Decal	1	1
4	Insulator Pad	1	1
5	Decal, AC Input Voltage	1	1
6	Decal, DC Output Voltage	-	1
7	Fuse Package, 5 fuses/pkg, 250 V		
	5 A	1	1
	3 A	-	1
	.315 A	-	1
8	2.75" x .25" Hex Spacer	5	5
9	2.0" x .31" Hex Spacer	4	4
10	Ground Braid Cable	1	1
	#8-32 Phillips Head Screw	8	8
	#8 Lockwasher	5	5

Appendix 1 – Battery Replacement

Replacing the Cooper Form 6 Battery

1. Remove the control from service as follows:
2. Enable GND TRIP BLOCKED to allow for ground trip to be disabled when reenergized.
   a) Press the CHANGE button on the Operator Panel to enter the CHANGE mode.
   b) Press the GND TRIP BLOCKED button within ten seconds after entering the CHANGE mode.
   Note: If the GND TRIP BLOCK button is not pressed within ten seconds, the function is not activated.
3. Disconnect the battery.
4. Remove the control AC sensing and power connections from the control using a separate disconnect switch.

WARNING: Hazardous voltage. If the recloser is energized while the control cable is disconnected, the CT secondaries can generate high voltages. Contact with high voltage can cause severe personal injury or death.

CAUTION: Equipment misoperation. Disconnect all control power sources prior to disconnecting the control cable from the control. Failure to comply can result in recloser misoperation at the time of disconnection or reconnection of the control cable to the control.

5. Disconnect the control cable from the control.
   Note: Do not disconnect any of the three recloser cables from the Reclosers or junction box unless all of the above steps have been completed.

CAUTION: Hazardous voltage. Cable conductors attached to NOVA Reclosers will remain at 53VDC potential after disconnection of source power to the recloser. Contact with any pins at the end of cables directly or indirectly connected to a NOVA recloser can result in personal injury or equipment damage.

6. Remove any control input and status output wiring from TB1, TB3, and TB4.
7. Disconnect any serial communications ports and IRIG-B timing connections.
8. Disconnect the ground from the control.
9. Disconnect and remove the battery.
10. Install the replacement battery.

CAUTION: Equipment misoperation. Do not connect this control to an energized recloser until all control settings have been properly programmed and verified.

11. Reconnect the ground cable to the control.
12. Ensure the cable is properly connected and supported.

13. Plug in the control battery.

Note: The Form 6-TS recloser control will not power up until AC power is applied.

CAUTION: Equipment misoperation. Verify that the 120/240 VAC selector switch is correctly set for incoming voltage. Failure to comply may cause misoperation (unintentional operation) of the control and/or equipment damage resulting in personal injury.

14. Verify the selector switch on the Power Supply / Battery Charger Board is set to the correct position based on the incoming power supply:
    - For 120 VAC incoming power, the selector switch must be set to the 115V position.
    - For 240 VAC incoming power, the selector switch must be set to the 230V position.
15. Apply AC power to the control.
16. Disable GND TRIP BLOCKED.
    a) Press the CHANGE button on the Operator Panel to enter the CHANGE mode.
    b) Press the GND TRIP BLOCKED button within ten seconds after entering the CHANGE mode.

Note: Once selected (or after ten seconds), the control returns to normal operation.

17. Verify the control clock is set to the current time after AC power has been reapplied.

    Note: The control clock may require resetting if the operating power has been disconnected for more than 30 days. Refer to the manufacturer's technical manual for details.

APPENDIX 10

INSPECTION, TREATMENT, RESTORATION AND REPLACEMENT GUIDELINES DISTRIBUTION SYSTEM WOOD POLES

5.61 Wood Poles

General Description

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities. This applies to all wood distribution poles within the custodianship or the maintenance responsibility of Eversource Energy. It shall include push braces and guying stub poles as well as line poles scheduled for the given year.

Facilities/Equipment

- Wood Poles

5.61.1 Inspection and Maintenance Activity Schedules

5.61.1.1 Table 1 – Wood Poles Maintenance Intervals

Wood Poles **Maintenance Schedule**	**All**
PM Task	
Condition Monitoring	N/A
Time-Directed	
Routine Inspection	15Y (**Notes 1 & 2**)
Condition-Based	
Priority Reject	**(Note 3)**
Schedule repairs or replacement.	A/R **(Note 4)**
Failure Finding	
Corrective Maintenance	A/R

In **Table 1**, the intersection of the row and column indicate the age-based inspection or maintenance interval for wood poles based on the preservation treatment listed in the column heading. For example, the age requirement for a Routine Inspection is 15Y (or 15 Years). The abbreviations used for the intervals are:
Y = Year, i.e. 2Y = 2 Years **A/R** = As Required
N/A = Not Applicable

Note 1 = 15 years is the minimum requirement for pole inspection. This interval may be changed due to contractual requirements with joint owners.
Note 2 = The type of inspection performed shall be determined by the age of the pole and its type of treatment, as shown in the following table:

Inspection Type	Creosote, Penta, all others	CC
Visual	0 to 9 years old	0 to 19 years old
Sound & Bore	10 to 14 years old	20 years old and older
Ground Line Evacuate	15 years old and older	If decay is indicated by Sound & Bore

Note 3 = Check the pole within 48 hours and make the pole safe within 5 working days.
Note 4 = Complete the repair or replacement within one year of determination of need following inspection

5.61.2 Maintenance Categories

5.61.2.1 Routine Inspection – Time Directed
1. Routine inspection activities are detailed in EMP Instruction 6.61.

5.61.2.2 Priority Reject Poles
1. Priority reject pole activities are detailed in EMP Instruction 6.61.

5.61.2.3 Normal Reject Poles
1. Normal reject pole activities are detailed in EMP Instruction 6.61.

5.61.3 Evaluation of Restorable Poles
1. The evaluation activities for restorable poles are detailed in EMP Instruction 6.61A.

5.61.4 Failure Finding
1. Failure finding activities are detailed in EMP Instructions 6.61 and 6.61A.

5.61.5 Research/Background
Publications and other reference materials from these organizations were used in the development of this program.
- National Electric Safety Code, as directed by section DER 07-01 “Wood Poles – Aging Infrastructure”
- TD 953 – “Inspection, Treatment, Restoration and Replacement Guidelines for Dist Sys Wood Poles”

5.61.6 Wood Poles - Maintenance Basis Documentation
The maintenance activities and their schedules are based on industry experience, manufacturer’s recommendations, feedback from the service technicians, and the subject matter expert, who in this case, is a Senior Engineering Technologist for Distribution Engineering Design.

Requirement	Basis
Routine Inspection at 15Y Interval	**Inspection required by the NESC -** The National Electrical Safety Code requires that poles are inspected as often as experience shows it necessary to maintain the strength required for the pole to remain in service. According to charts developed by Osmose on National averages, the percentage of reject poles starts to rise between ten and fifteen years. However, because Eversource is mostly in a "Moderate Deterioration" zone (National Wood Preservers Association Book of Standards) we could expect better than average results from an inspection program. Eversource's experience finds that a fifteen year inspection and treating program keeps the reject rate reasonable. NOTE: Eversource's line mechanics are taught to visually inspect and sound any pole before climbing it. The 15 year inspection is required, but it is acknowledged that PSNH has an existing contract to perform their inspections at a 10 year interval.

EMP 6.61 - Routine Inspection

Visual

A visual (only) inspection is to be performed on:

- CCA Treated Poles ----------0 – 19 years old
- Creosote, Penta, and all other poles---------- 0 – 9 years old

This shall be the first step for inspecting each pole, and shall include a thorough observation of the above-ground portion of each pole and all attachments. Record any findings into the system appropriate for the activities being performed.

1. Visually inspect the pole for the following defects:
   - Pole top split or deteriorated
   - Crossarm damaged or decayed
   - Broken or damaged insulator
   - Broken or damaged spacer
   - Buried anchor guy
   - Broken guy wire
   - Leaning pole
2. Check to see if the pole is set shallow. The following table indicates the correct distance from the ground-line to the bottom of the pole brand:

Length of Pole (in feet)	Groundline Distance	
	To Butt	To Brand
25	5	5
30	5.5	4.5
35	6	4
40	6	4
45	6.5	3.5
50	7	3
55	7.5	6.5

- Measure the distance from the ground line to the bottom of the pole brand. If the distance is *more than 6 inches greater* than the value in the 3rd column of the above table:

  a. Attach an aluminum pole tag letter "**S**" just below the bottom of the pole brand.
  b. Record the information into Cascade or into the appropriate inspection record.

- *Do not* record this pole as set shallow if there is an "**R**" tag attached to the pole just below its brand, as this indicates the presence of enough rock to support the pole.

3. Install a reflector on all wood poles located within six feet (6 FT) of any roadway if no guard rail is present. The reflector shall be installed on the wood pole in accordance with DTR 05.091 and in the direction of travel. If unable to install, no follow-up action is required.

Sound & Bore Inspection Pole in Ground

A Sound & Bore Inspection is performed on:

- CCA treated poles----------20 years old and older
- Creosote, Penta, and all other poles --- 10 – 14 years old.

1. Sound the pole all around, listening for hollow sounds that may indicate decay or insect damage.
   - Strike the pole firmly (not hard) with a hammer from the ground line upward to as high as you can reach, approximately 8 feet above the ground line.
   - Striking intervals shall be 2" to 3" apart at ground line and where ever decay or insect damage is suspected.
   - Above the ground line, use 12" intervals.
2. Pull back the soil at ground line on two sides of the pole, giving pullback priority to any suspicious sounding areas or visually suspect areas.
   - Each pullback should be approximately shovel's depth and 6" wide.
3. Bore a 3/8" hole into the pole at a 45 degree angle from the ground line to the center of the pole, and wherever there were any suspicious areas detected by sounding, in order to detect insect damage or damage due to decay.
   - If no insect damage or decay is detected, do not treat the pole.
4. Evacuate any voids found within the pole
   - If the pole passes inspection, fill the void and coat the outside with the appropriate treatments.
5. Plug all bored holes with 7/16" treated dowels (2" to 3" long), and tamp the pulled-back soil neatly into place.

Sound & Bore Inspection – Poles In Pavement

This includes those poles that are surrounded by pavement, or that have riser pipes or other obstructions that prevent excavation.

A Sound & Bore inspection is performed on:

- CCA treated poles ---------- 20 years old and older
- Creosote, Penta, and all other poles--------10 - 14 years old

1. Bore each pole with the 3/8 inch x 18 inch or 24 inch inspection bit at a 45 degree angle from above ground line to below ground line to look for decay or insect damage.
2. Evaluate decay as specified in the Circumference Measurement section on page 5.
3. Treat the pole. If the pole exhibits some decay, but still passes inspection, internally treat the pole with:
   - "WOODFUME" if there are no internal voids
   - "Hollow Heart" if there are internal voids.
   - MITC-FUME/MP400-EXT/OSMOSHIELD as appropriate

Ground Line Inspection

A ground line inspection is performed on:

- Creosote, Penta and all other poles -------- 15 years old and older

> **NOTE**: *Do not* excavate a pole set shallow until Division Operations advises that the situation has been corrected.

1. Excavate each pole all around to a depth of 18 inches, leaving at least 4 inches of radial clearance at the bottom of the excavation.
2. Use a wire brush to clean the below-ground portion of the pole and use a check scraper to locate any exterior decay.
3. Sound the pole all around.
4. Bore a 3/8" hole into each pole at a 45 degree angle from the ground line to the center of the pole and wherever decay or insect damage is suspected.
5. Plug all bored holes with a 7/16" preservative treated wood dowel (2" – 3" long).
6. Use a shell thickness indicator to measure voids and the thickness of the outer shell.
7. Remove by chipping, all loose weathered wood and wood overhanging deteriorated wood to at least 6 inches above ground line. See the following section on Circumference Measurements.
8. Remove all exterior wood from the pole surface to be treated using care not to remove any sound wood unless that is essential to inspection/treatment.
9. Remove all chipped wood debris from the hole and properly dispose of it away from the site.

Circumference Measurement

Evaluate a pole if its effective ground line circumference has been reduced by decay or insect pockets, hollow heart, mechanical damage or has had exterior decayed wood removed by chipping prior to ground line treatment.

Calculate the percentage of the remaining pole strength based on the effective ground line circumference and the existing conductor and attachment load. Remove from service, any corner (angle) poles,

dead end poles, guy stubs and push braces with less than 80% of their original ground line circumference. Circumference measurements for new poles are listed below in the following table.

Length of Pole or Feet From Top	Minimum Dimension (in Inches)	Class						
		H-2	H-1	1	2	3	4	5
0’	Diameter	9.9	9.2	8.6	8.0	7.3	6.7	6.0
	Circumference	31.0	29.0	27.0	25.0	23.0	21.0	19.0
2’	Diameter	10.2	9.5	8.8	8.2	7.5	6.9	6.3
	Circumference	31.9	29.8	27.8	25.8	23.7	21.7	19.7
5’	Diameter	10.6	9.9	9.3	8.6	7.9	7.3	6.6
	Circumference	33.2	31.1	29.1	27.0	24.9	22.8	19.7
10’	Diameter	11.3	10.6	9.6	8.9	8.3	7.7	7.0
	Circumference	35.4	33.2	30.0	28.0	26.0	24.0	22.0
15’	Diameter	12.0	11.2	9.9	9.2	8.6	8.0	7.3
	Circumference	37.6	35.3	31.0	29.0	27.0	25.0	23.0
20’	Diameter	12.7	11.9	10.7	10.0	9.4	8.8	8.1
	Circumference	39.8	37.4	33.5	31.5	29.5	27.5	25.5
25’	Diameter	13.4	12.6	11.6	10.9	10.2	9.5	8.7
	Circumference	42.0	39.5	36.5	34.0	32.0	29.5	27.5
30’	Diameter	13.8	13.2	12.4	11.6	10.9	10.0	9.2
	Circumference	43.5	41.5	39.0	36.5	34.0	31.5	29.0
35’	Diameter	14.6	13.8	13.1	12.3	11.5	10.7	9.9
	Circumference	46.0	43.5	43.5	38.5	36.0	33.5	31.0
40’	Diameter	15.4	14.5	13.7	12.8	11.9	11.1	10.3
	Circumference	48.5	45.5	43.0	40.5	37.5	35.0	32.5
45’	Diameter	16.1	15.1	14.3	13.3	12.0	11.7	
	Circumference	50.5	47.5	45.0	42.0	39.0	36.5	
50’	Diameter	16.6	15.8	14.7	13.8	12.9		
	Circumference	52.0	49.5	46.5	43.5	40.5		

Ground line (diameter or circumference) dimensions for a pole are measured at 5 feet from the bottom of the pole.

Reject Poles

Priority Poles

Reject all priority poles. A priority pole is one which is in imminent danger of falling because it is completely decayed across the grain, or it has a hollow heart with sound wood in the outer shell of one inch thickness or less.

- Use the C-aluminum pole tag which measures 2 inches high and 2-1/2 inches wide. It has a clear aluminum arrow with an “X” inscribed in a circle imposed on the shaft of the arrow on a red background.

- Paint a yellow “X”, approximately 1 foot square in size, on the roadside of the pole, centered approximately 6 feet above the ground line. Then, attach one C tag centered on the “X” and attach another C tag at approximately the same height on the field side of the pole.
- If the pole is defective in the ground line section, place the tags so the arrow points downward. If the pole is defective in the upper portion, place the tags so the arrow points upward. If, however, the pole is defective in both the ground line section and in the upper portion place a double set of tags, one set with the arrow pointing downward and the other set with the arrow pointing upward. Attach the tags with 1-1/4 inch galvanized roofing nails.
- **Report the pole immediately** by telephone, radio, or email (whichever is appropriate for your company requirements) to the appropriate district.
- Record the information in the computer database and include the name of the person the reject information was reported to in the comments section.

NOTE: Field Supervision shall check the pole within 48 hours from identification as “priority reject” to assess the conditions and verify there is no immediate danger to the public. The pole must be made safe within 10 calendar days or less from its identification as “priority reject” wood pole.

Normal Reject Poles

Normal reject poles are those poles which have effective circumferences equal to or less than the minimum ground line circumference at replacement (normally 67% of original circumference) but which are not deteriorated enough to be classified as “priority poles”. Circumference measurements for new poles will be provided in the Instructions chapter.

- Reject decayed poles having a minimum shell thickness of less than 2 inches.
  - If the hollow heart is the result of severe ant or termite infestation, then reject those poles having a minimum shell thickness of less than 3 inches.
- Normal reject poles shall be identified as follows:
  - Use the B-aluminum pole tag which measures 2 inches high and 2-1/2 inches wide. It has a clear aluminum arrow on a red background.
  - Attachment instructions for the B tag are the same as for the C tag used to identify priority poles in the preceding section.

Refer to Instruction EMP 6.61A for details on evaluating “Normal” reject poles and performing their restoration

Research/Background

Publications and other reference materials from these organizations were used in the development of this program.

- National Electric Safety Code, as directed by section DER 07-01 “Wood Poles – Aging Infrastructure”
- TD 953 Rev. 2 – Inspection, Treatment, Restoration and Replacement

Guidelines for Distribution System Wood Poles

- PSNH Procedure CO-1009 – Climbing Inspections
- Over-Under OH05-090 – Tagging Defective Poles
- Over-Under OH05-245 – Woodpecker Damage
- TD-067 – Pole Numbering
- TD-234 – Re-Use of Treated Wood
- Transmission Vegetation Management Wood Pole Inspection
- Wood Poles Restoration Guidelines (from Jeff Smith)
- EMP Section 6.61A – Wood Pole Restoration (instructions)
- DTR 05.101

6.61 A Wood Pole Restoration

This section of the Eversource Maintenance Manual provides instruction for determining which Reject Poles (as defined in section 6.61 of the manual) are suitable for repair or restoration as a means to extend their useful life by at least:

- 15 years* (the inspection interval for wood poles not planned for replacement) or
- 5 years (for poles scheduled for replacement within that period)

It also provides guidelines for determining which poles may not be restored.

Guidelines for Reject Pole Restoration

All of the following requirements must be met in order to qualify a pole for restoration:

1. No circuit rebuild requiring taller or larger class poles is planned within the present planning period. Search the Work Management System by pole number to determine if other work has been planned for that pole and proceed accordingly.
2. No equipment additions (capacitors, reclosers, regulators, switches or transformers) that would require a taller or larger class pole are expected in the near future.
3. Telephone Company concurs with pole restoration for those poles jointly owned. (Refer to guidelines for jointly owned poles below).
4. If applicable, State Highway Department concurs with pole restoration for poles along state highways. For the State of Connecticut, written approval must first be obtained from the appointing authority of the local municipality of the state route where pole restoration is planned. A permit by the State of Connecticut Department of Transportation will not be issued unless approval from the municipality is included with the request.

Restoration Guidelines for poles jointly owned with Frontier (Connecticut only):
Frontier encourages pole restoration for the following cases:

- Pole with Frontier aerial or ground level interface boxes attached.
- Poles with large communication cable risers attached.
- Poles in Right of Ways.
- Poles 45 feet and above.

Guidelines for Reject Pole Replacement
Reject poles are categorized as either a Normal Reject or a Priority Reject pole, as follows:

- A **Priority Reject** pole is one which is in imminent danger of falling because it is completely decayed across the grain, or is a pole having a hollow heart with sound wood in the outer shell of one inch thickness or less.
- A **Normal Reject** pole is one that has an effective circumference equal to or less than the Minimum Ground line Circumference at Replacement (normally 67% of original circumference) but which is not deteriorated enough to be classified as a "Priority Reject" pole.

1. Replace all poles found to be Priority Reject poles.
2. Evaluate the condition of the entire pole. If there are cracks, splits, or rot at the top, extensive woodpecker holes, or other damage that would make it impractical to extend the life of the pole by restoring the pole at the ground line, then the pole should be replaced rather than restored.
    - **Exception to this rule:** If you know that the pole will be relocated or replaced for other reasons within the next five years, and restoration will extend its life at least for that period, then restore the pole instead of replacing it.
3. Assess the need to climb the pole in the future. If the pole cannot be easily reached with a bucket truck **and** the condition of the pole above the ground line is not sufficient to allow climbing, then replace the pole.
4. Determine if the pole is the correct class and height to support the facilities that are on it. The Eversource Distribution Standards provide the required clearances and guidance to calculate the strength requirements to support the electric and communications equipment. If it is determined that the existing pole is not sufficient due to strength or clearance issues, then replace it with the correct class and height pole.
5. Return to Distribution Maintenance and Construction a list of those poles which you have confirmed can be restored. For those which you have determined cannot be restored, state the reason(s) in writing why they cannot be restored.
6. Replace poles on scenic highways or in historical areas of towns (Connecticut only).

Guidelines to replace defective poles jointly owned with Frontier (Connecticut only):

Frontier encourages replacing defective poles under the following conditions:

1. Replace 35' poles with power primary, secondary/neutral and communications cables that cross a road. Poles with 3 phase primary, secondary and communications equipment should be replaced with a tall pole to provide access to the field side of the pole if the 35' pole is found to be defective. See DTR 04.047.
2. Replace 35' poles with power primary, secondary/neutral and more than 3 attachments in the communications gains.
3. Replace 40' poles with power primary, secondary/neutral and more than 5 attachments in the communications gain. Evaluate the pole height to ensure that proper clearance requirements are met.
4. Replace any pole that is inadequate for planned Frontier construction.
5. Replace any pole that does not meet Frontier or State of Connecticut DOT criteria for pole restoration.

NOTES:

- Attachments in the communication gain refer to all attachments, roadside and field side, including bare strand. (Frontier, Municipal, State, CATV, other communication companies).
- Questionable poles will be reviewed by Frontier Line construction/Frontier engineering upon request.
- It is requested that pole maps of the projected pole inspection be supplied to Frontier for review. Frontier will identify areas of planned construction and reply back to Eversource.

Pole Restoration

Poles evaluated as **normal reject** poles by the inspector shall be noted in the computer database as "Restorable" if there is sufficient shell thickness to transfer the strength of the steel reinforcing member to the wood pole. A normal reject pole is restorable with one of the following options if it meets the following minimum criteria.

C-Truss System

1. Sound the pole thoroughly above the ground line again. Concentrate at the zone 15 inches to 4-1/2 feet above the ground line.
2. Drill at 4-1/2 feet above the ground line against the line of lead.
    - If this boring indicates less than a 4 inch shell thickness a second boring is made opposite (180 degrees from) the first boring whenever possible. Other borings should be taken as necessary.
        - If the average shell thickness is 4 inches or more at the 4-1/2 foot height, the pole can be restored using a C-Truss.
        - If the average shell thickness is less than 4 inches at the 4-1/2 foot height, the pole should be bored at 5-1/2 feet. If the average shell thickness is 4 inches at this height, Then the pole can be restored using a *larger* C-Truss.
        - If the average shell thickness is less than 4 inches at both 4-1/2 and – 5-1/2 foot heights, then use a Fiberwrap System to restore the pole.

3. Drill at 15 inches above the ground line against the line of lead.
    - If this boring indicates less than a 2 inches shell thickness, a second boring is made opposite (180 degrees from) the first boring whenever possible. Other borings should be taken as necessary.
        - If the average shell thickness at 15 inches is 2 inches, the pole can be restored using a C-Truss.
        - If the average shell thickness at 15 inches is less than 2 inches, bore the pole at a 26 inch height. If there is a 2 inch average at the 26 inch height, the pole can be restored using the *larger* C-Truss.
        - If the average shell thickness at both 15 inch and 26 inch heights is less than 2 inches, then use a Fiberwrap System to restore the pole.

Fiberwrap System

1. Drill at 6 feet above the ground line against the line of lead.
    - If this boring indicates less than a 4 inch shell thickness, a second boring is made opposite (180o from) the first boring whenever possible. Other borings should be taken as necessary.
        - If the average shell thickness is 4 inches or more the pole can be restored using a Fiberwrap.
        - If the average shell thickness is less than 4 inches, continue boring at 6 inch intervals up the pole until a 4 inch average shell thickness is obtained or the height of 10 feet is reached.
        - If 4 inches of shell thickness if found at a height of 10 feet or less, the pole can be restored using a Fiberwrap.
        - If an average of a 4 inch shell does not exist from 6 to10 feet, the pole cannot be restored.

APPENDIX 11

UNDERGROUND SWITCHES

5.51 Underground Switches

General Description

Underground systems contain many types of switches. There are oil switches, oil-vacuum switches, fusible switches, SF6 vacuum switches, etc. The switches generally are constructed for submersible application and are located in manholes, vaults or on concrete pads in subway system areas. The purpose of these switches is to isolate sections of circuits in order to minimize the number of customers interrupted due to faults on the circuits or to transfer loads from one circuit to another.

Many of the older types of switches have been replaced over the years as 5 kV and below systems have been converted to systems ranging from 15 kV to 35 kV. There are projects to convert more of the 5 kV and below systems to the 15 kV to 35 kV range. Completion of these projects will result in the removal of more of the older types of switches. Switches installed in these conversion areas and in new underground areas are the standard SF6 vacuum switches. Industry-standard rubber molded products are used to connect the switches to Tree Retardant XLink or ethylene propylene rubber insulated primary cables.

5.51.1 Inspection and Maintenance Activity Schedules

Table 1 – Underground Switch Maintenance Intervals

Underground Switches Maintenance Schedule	**Interval**
PM Task	
Condition Monitoring	N/A
Time-Directed	
Routine Inspection – Energized	15Y
Condition-Based	
Correct any defects found during Routine Inspection	A/R
Inspect suspect equipment or conditions previously reported	1Y (**Note 1**)
Failure Finding	
Appropriate Failure Reporting System (EFRS, UPER, Cascade, etc)	A/R
Failure Investigation	A/R
Scheduling Requirements	
Perform together with subway system (radial) - cable	A/R

In **Table 1**, the intersection of the row and column indicate the inspection or maintenance interval for the equipment in the column heading. For example, the interval for a Routine Inspection is 5Y (or 5 Years). The abbreviations used for the intervals are:
Y = Year, i.e. 2Y = 2 Years
A/R = As Required
N/A = Not Applicable

Note 1 Equipment or conditions may exist that require monitoring on a basis more frequent than the 5Y Routine Inspection.

5.51.2 Maintenance Categories

Refer to EMP Instruction 6.51 for details on performing the following maintenance tasks

TIME-DIRECTED

5.51.2.1 Routine Inspection – Energized

Refer to EMP Instruction 6.51 for details on performing the routine inspection for underground switches.

CONDITION-BASED

Correct any conditions found during Routine Inspection or record the conditions and schedule them for future replacement.

5.51.3 Failure Finding

A failure report shall be completed for any subway switch failure and placed in the appropriate failure tracking system (EFRS, UPER, Cascade, etc.) for review by Distribution Standards.

Analysis of of subway switch failures should be performed when deemed necessary by Distribution Standards.

5.51.4 Related Documents

- Product Review 132, Dated 10-30-02 – Describes Load Break Elbow Pulling Tools as used for Removing elbow connectors from transformers and other UG/DB apparatus.
- Product Review 133, Dated 11-07-02 – Provides alternative tools to loosen and remove “stuck” elbows and/or for performing DB./UG switching.
- CO-1004 – New Hampshire Loadbreak Elbow Procedure. Establishes guidelines for safe operation of loadbreak elbows during load break, load make switching and phasing of the underground systems at PSNH.
- TD 921 – Identifying molded rubber components with probable manufacturing defects

5.51.5 Maintenance Basis Documentation

The maintenance activities and their schedules are based on company past practices and the subject matter expert who is a Senior Engineer in the Distribution Engineering and Design Group.

Requirement	Basis
Routine Inspection – Energized at 5Y interval	The five year inspection of subway switches has been changed from the previous three year cycle to better coincide with other underground equipment maintenance. The SME from Distribution Engineering and Design along with Maintenance personnel agree this should be the new interval.

5.51.6 Condition Monitoring/Maintenance
N/A

6.51 Underground Switch Maintenance Instructions

Before You Begin

Prior to assigning work on underground switches, Supervision shall:

1. Ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
    - TD 211, “When to Wear FR Clothing”
    - TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut and Western Massachusetts only)
    - TD 955, “Confined Space Requirements”
    - Eversource Employee Safety Manual
2. Ensure those performing the work are aware of the following PPE Requirements whenever working in Underground manholes or vaults:
    - Safety Glasses with side shields
    - EH (Electrical Hazard) rated boots
    - High Voltage gloves
    - FR (flame resistant) clothing, as specified in TD 211
3. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check manholes and vaults prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.
4. Review the manufacturer’s manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
5. Prepare the manhole or vault for entry.
    a) Check for dangerous atmospheric conditions before entering the manhole using company-approved atmospheric sampling equipment.
    b) Ventilate the manhole or vault, if required, in accordance with the Eversource Employee Safety Manual
    c) Remove any standing water or debris from the manhole or vault in accordance with ENVIROWI-0105 or company-specific

requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

6. Place the circuit in “non-recloser” mode; this disables the automatic closing of a protective device following automatic tripping, thus preventing the re-energizing of the distribution line.
7. Apply “Hotline” tags to the circuit, where available. A Hotline Tag is an alternative setting used on some reclosers and substation breakers that place the device on a fast-trip curve and blocks reclosing.

Routine Inspection – Preparation

Supervisor, planner or working foreman (as appropriate)

1. Check for open work orders (such as leaking splices) for this location that may indicate unsafe conditions or that may present the opportunity for combining maintenance at this or adjacent vaults. Ensure Copies are provided to the crew performing the inspection.
2. Provide equipment prints / schematics / circuit maps for this location so that the actual field conditions, i.e. transformer size, etc. can be verified by the crew performing the inspection.

Routine Inspection – Performance

Inspection Crew

1. Check for stray voltage in accordance with EMP 6.62 - Touch Potential.
2. Ensure equipment nomenclature and status indicators are present and in good condition. Clean or replace as required.
    - Ensure the work order matches the ID tag and that all identification and Location numbers are correct.
3. Observe the exterior of the switch for any other significant defect or abnormal condition that may affect the safe operation of the switch, such as excessive damage / corrosion to the unit or other defect that requires immediate repair.
4. Check the switch for any discoloration.
5. Check that switch is physically secured in place.
6. Ensure the switch is properly grounded to the manhole, vault, or concrete pad ground grid, if possible.
7. Visually check the switch for leaks. If a gauge is available, record the pressure / level.
8. Perform an infrared inspection to check for heat anomalies on primary connections, secondary connections and accessories, as applicable. Refer to EMP 5.22 for additional guidance.

> **NOTE**:
> Perform the Infrared (IR) inspection using an infrared camera. If an infrared camera is not available, a temperature reading tool, such as the Fluke 63 (SC 0435572) may be used to take spot temperature readings of the equipment in place of the IR inspection.

9. Refer to manufacturer’s manuals for specific requirements for the switch being serviced.

Underground Switches Form Routine - Energized
EMP 6.51-1 Guideline

	Inspect	Inspection Attributes
1	Stray Voltage	Check for stray voltage in accordance with EMP 6.62 - Touch Potential
2	Nomenclature and Status Indicators	Ensure equipment nomenclature and status indicators are present and in good condition. Clean or replace as required. Ensure the work order matches the ID tag and that all identification and location numbers are correct.
3	Significant Defect or Abnormal Condition	Observe the exterior of the switch for any other significant defect or abnormal condition that may affect the safe operation of the switch, such as excessive damage / corrosion to the unit or other defect that requires immediate repair.
4	Discoloration	Check the switch for any discoloration
5	Mounting	Check that switch is physically secured in place
6	Grounding	Ensure the switch is properly grounded to the manhole, vault, or concrete pad ground grid, if possible
7	Check for leaks	Visually check the switch for leaks. If a gauge is available, record the pressure / level
8	Infrared Inspection	Perform an infrared inspection to check for heat anomalies on primary connections, secondary connections and accessories, as applicable. Refer to EMP 5.22 for additional guidance

APPENDIX 12

UNDERGROUND SYSTEM - NETWORK TRANSFORMERS

5.30 Network Transformers

General Description

A network transformer transforms a primary voltage down to the voltage of a secondary network grid. A network transformer is designed and constructed to operate in harsh environments such as street vaults, sidewalk vaults and customer building vaults.

A network transformer consists of two main sections. The first section is the main tank in which the core and coils are located and the second section is the high voltage switch. The *standard* network transformer has a one-compartment high voltage switch, but there are also network transformers with a two-compartment high voltage switch in service. One compartment of this high voltage switch contains the switch mechanism and the other compartment is the high voltage termination compartment.

The insulating fluid that is in the main tank of a standard network transformer is transformer oil and the insulating fluid that is in the high voltage switch of a standard network transformer is a less flammable insulating fluid. There are other network transformers in service with other insulating fluids in the main tank and high voltage switch. Also, the termination compartment of a high voltage switch may contain insulating fluids or compounds which may be PCB contaminated. For these reasons, it is essential to check the nameplates for each network transformer to identify all of the insulating fluids.

NOTE: All specific maintenance requirements that are followed by a triangle symbol "▲" are explained in the Maintenance Basis Documentation section of this chapter.

5.30.1 Inspection and Maintenance Activity Schedules

5.30.1.1 Table 1 – Network Transformer Maintenance Intervals

NETWORK TRANSFORMER Maintenance Schedule	All Models
PM Task	
Time Based	
Routine Inspection – Energized ▲	1Y
Routine Inspection – De-Energized ▲	4Y
Condition Based	
Any defects found during Routine Inspection, such as oil leaks, failed pressure test, unexplained temperature changes, etc.	A/R

Failure Finding	
Equipment Failure Reporting System used by your region (EFRS, UPER, etc.)	A/R
Failure Investigation	A/R
Scheduling Requirements	
Perform together with Network Protector Maintenance	
Perform together with Vault Inspections	

In **Table 1**, the intersection of the row and column indicate the inspection or maintenance interval for the equipment in the column heading. For example, the interval for a Routine Inspection - Energized for all models of Network Transformers is 1Y (or one year). The abbreviations used for the intervals are:
Y = Year, i.e. 1Y = 1 year
A/R = As Required

5.30.2 Maintenance Activities

TIME-DIRECTED

5.30.2.1 Routine Inspection – Energized ▲

Refer to EMP Instruction 6.30A for details

5.30.2.2 Routine Inspection – De-Energized ▲

Refer to EMP Instruction 6.30A for details

5.30.2.3 Network Transformer References:

- Electric Utility Line Maintenance Plan
- EMP
- Industry Experience
- TD202 Oil Sampling and Analysis
- Eversource Employee Safety Manual

5.30.3 Failure Finding

A failure report shall be completed for any network transformer failure, submitted to the equipment failure reporting system used by your region (EFRS, UPER, Cascade, etc.), and placed in “To Eng” status for review by Distribution Standards.

Analysis of network transformer failures should be performed when deemed necessary by Distribution Standards.

5.30.4 Network Transformer Maintenance Basis Documentation
The maintenance activities and their schedules are based on industry experience, manufacturer's recommendations, feedback from service technicians, and subject matter expert who is a Senior Engineer for Distribution Engineering and Design.

Requirement	Basis
Routine Maintenance – Energized at 1Y interval.	The annual inspection of the network transformer and switch, performed energized, has historically been the accepted frequency cycle for this equipment. No information, either internal or external to Eversource, has been found to suggest a change to this frequency cycle is warranted and will continue to be required annually.
Major Maintenance - De-energized at 4Y Interval. (To be performed with Network Protector Major Maintenance.)	In general, in their product literature, network transformer manufacturers suggest periodic sampling and testing of the fluid in high voltage switches and network transformers. However, there is no mention of the length of time between taking the samples. A survey of an approximate dozen other utilities indicated that a small percentage do sample the fluid in high voltage switches and network transformers, but there was no common time period given. It was determined that the consequences of a network transformer failure would not significantly affect system reliability. In addition, the Working Group consensus identified that the failure history for network transformers is very low. As a result, a two year interval for performing de-energized inspections was selected. As data is collected and examined, this interval may be changed.

6.30 Network Transformer Maintenance Instructions

Before You Begin
Prior to assigning work in Underground Vaults & Manholes, Supervision shall:

1. Ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
    - TD 211, "When to Wear FR Clothing"
    - TD 952, "Protection of Personnel Entering Enclosed

Spaces" (CL&P, WMECO, and NUSCO only)

- TD 955, "Confined Space Requirements"
- Eversource Employee Safety Manual
- TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (CL&P ONLY)

2. Ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
    - Safety Glasses with side shields
    - EH (Electrical Hazard) rated boots
    - High Voltage gloves
    - FR (flame resistant) clothing, as specified in TD 211
3. Whenever "Work" is performed on a network unit as defined in paragraph 5 of this procedure, the following PPE is required :
    - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or company approved equivalent.
    - Safety glasses with side shields
    - Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)
    - Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall)
4. All persons performing "Work" on Network Units as defined below and those persons within the immediate work zone while "Work" is being performed shall wear at minimum double layer full body FR clothing, minimum 25 cal. FR rated hood (beehive type with built-in arc rated face shield), safety glasses and, minimum of low voltage (Class 0) rubber gloves (high voltage rubber gloves preferred). As defined in this document, "Work" includes the following tasks:
    - Installing or removing transformer links and network fuses
    - Rolling or racking out the protector
    - Phasing the unit
    - Connecting test leads to an energized bus
    - Obtaining transformer and network voltages
    - Test probe usage prior to installing links and network fuses
    - Or any other work performed inside the network protector enclosure with the transformer and/or network bus energized
5. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
    - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to Connecticut and Western Mass)

- If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
- The deficiencies described below, require the primary circuit to be de-energize in accordance with the operating policy.
    - Major maintenance not performed within the maintenance cycle required by the Eversource maintenance manual
    - Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level
    - Any other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage / corrosion in the network protector or other defect that requires immediate repair to return to service.

6. For cases where multiple network transformers exist in a vault, it will generally not be possible to de-energize all of those units for a variety of reasons. Therefore, prior to working on a network transformer, where multiple network transformers exist in a vault, maintenance records shall be reviewed for major deficiencies and/or major maintenance completion within the maintenance cycle per the Eversource Maintenance Program prior to working in the vault.
    - If records indicate that major maintenance for all transformers within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
    - If major deficiencies or major maintenance was not completed, management will jointly work with employees for the appropriate steps to follow.
7. With the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro-filling) is being performed.
    - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
8. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or

traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.

9. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
10. Prepare the vault for entry.
    a) Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment
    b) Ventilate the vault, if required, in accordance with the NU System Employee Safety & Health Handbook.
    c) Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Routine Inspection – <u>Energized</u>

1. Check for stray voltage in accordance with EMP 6.62 - Touch Potential
2. Record the fluid level in the transformer using the liquid level gauge. The level should be between mid-scale and below top of scale (i.e. high but visible) If there is no oil indication, **immediately** stop the job and notify Supervision.

<u>CAUTION</u>
Continued operation of a Network Transformer with an abnormal main tank oil level requires Manager level approval.

<u>NOTE</u>:
Some transformers are equipped with magnetic mount oil gauges. These should be removed, cleaned and remounted to ensure their

3. Look for any other defect or abnormal condition that may affect the operation of the network transformer.
4. Verify the transformer nomenclature, if applicable. Clean or replace as necessary.
    - Ensure the work order matches the transformer ID tag and that all identification and location numbers are correct.
    - Ensure the PCB tag is in place. Replace as necessary.
5. Ensure that the high voltage switch position nameplates and nomenclature are visible and secure. Clean or replace as necessary.
6. Verify the high voltage switch is closed.

7. Check the primary cables for leaking or damaged splices, indications of tracking, and adequate cable support.
8. Check for transformer leaks.
    - Cooling Radiator (if present)
    - Leaking Termination (stuffing) box (if applicable)
    - Leaking Potheads (if applicable)

    Fix those that you can by tightening connections, etc. Report those leaks that can't be fixed at the time of this maintenance call.
9. Check the high voltage switch, including the termination compartment, when applicable, for leaks. Report those leaks that can't be fixed at the time of this maintenance call.
10. Check the transformer and the high voltage switch for any abnormalities such as:
    - Severe rust – or corrosion from road salt
    - Physical damage from falling concrete, vandalism, failed mounting rails, etc.
    - Indications of overheating
11. Record the fluid level in the high voltage switch using the gauge. The level should be between mid-scale and below top of scale (i.e. high but visible)

NOTE:
A new high voltage switch has one compartment and the fluid level is obtainable. For an older high voltage switch with two compartments, the fluid level in the termination compartment *MAY NOT* be verified with the transformer energized.

12. Record the peak temperature, if the gauge has a drag hand, and present temperature of the fluid in the transformer from the gauge. Reset the drag hand (if installed) to the present reading.
13. Observe the primary connections on the high voltage switch for any unusual conditions such as cracked lead wipe, discolored high voltage connection, signs of heat, etc.
14. Check the condition of the valve handles to ensure they are in good condition.
15. Ensure the valves are closed and that there are no leaks.
16. Ensure the transformer and protector have separate grounds to the ground grid or vault ground rod. Do not rely on the mount support to act as a ground for the protector.
17. Check for the presence of anodes and the condition of their connections (if anodes are installed). Replace if needed.

Major Maintenance – De-Energized

Note: It is acknowledged that switching protocols vary among locations. It is the responsibility of the technician performing the maintenance work to either perform the following steps or to ensure that they have been performed.

1. De-energize the primary network cable.

2. Ensure the cable is de-energized.
    - For those installations in which the primary network cables have a rack in ground and test device, rack in the ground and test device and then perform a **live – dead– live** test with a noisy tester.
    - For those installations in which the primary network cables *do not* have a rack in ground test device, perform a **live – dead – live** test with an approved tester, and then install grounds on the cable just above the pothead.
    - When the network transformer is de-energized, there will be no audible hum or vibration.
3. Ensure the network protector is in the **Open** position, in manual mode, and locked in order to prevent unintentional operation.
4. Verify the high side switch is closed.

***Warning**:* You must obtain permission from Dispatch before operating the high side switch on a network transformer. (CL&P and WMECO ONLY)

***Warning**:* There have been instances in which the roll pin that connects the high side switch handle to the operating shaft has failed on Carte transformers. This has allowed the handle to move without actually rotating the operating shaft, thereby causing a false reading of the switch's position.

5. On **Carte** transformers, inspect the pin that connects the high side switch handle to the operating shaft. Replace it with a new, solid pin if it shows any signs of corrosion or damage.
6. Obtain a fluid sample from the transformer and the high voltage switch and replenish the fluids.
    - Record the date and quantity of oil added to the main tank to replenish level in the Network Transformer
    - Refer to TD202 to ensure compliance with ChemLab requirements.
    - Submit the fluid samples for testing
7. Pressure-test the transformer main tank and the high voltage switch. Slowly pressurize each with nitrogen to 3.0 PSI (or Manufacturer's recommendations). Once stabilized, pressure should remain greater than 2.8 PSI for 30 minutes.
    - When the test passes, reduce the pressure to 0.5 PSI.
    - If the test fails, further investigation is required. Notify Supervision

Network Transformer Form Routine - Energized
EMP 6.30-1 Guideline

	INSPECT	INSPECTION ATTRIBUTES
1	Stray Voltage	Check for stray voltage in accordance with EMP 6.62 - Touch Potential
2	Check The Transformer Fluid Level	The level should be between mid-scale and below top of scale (i.e. high but visible) If there is no oil indication, **stop the job** and notify Supervision
3	Significant Defect Or Abnormal Condition	Look for any other significant defect or abnormal condition that may affect the safe operation of the network transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage / corrosion in the network protector or other defect
4	Verify The Transformer Nomenclature	Ensure the work order matches the transformer ID tag and that all identification and location numbers are correct. Clean or replace as necessary.
5	PCB Tag	Ensure it is in place. Replace as necessary
6	High Voltage Switch Position Nameplates	Ensure that the nameplate and nomenclature are visible and secure. Clean or replace as necessary
7	High Voltage Switch	1. Verify it is closed 2. When applicable, Check the high voltage switch for leaks (including the termination compartment)
8	Primary Cables & Connections	Check for any unusual conditions including: • indications of tracking, • adequate cable support • leaking or damaged splices, • cracked lead wipe • discolored high voltage connection, • signs of overheating
9	Leaks	1. Check for transformer leaks. 2. Check for Leaking Termination (stuffing) box. 3. Check for Leaking Potheads 4. high voltage switch, including the termination compartment
10	High Voltage Switch Fluid Level	Record the fluid level in the high voltage switch. The level should be between mid-scale and below top of scale (i.e. high but visible)
11	Temperature	Record the peak temperature, if the gauge has a drag hand, and present temperature of the fluid in the transformer from the gauge. Reset the drag hand (if installed) to the present reading
12	Valves	1. Check the condition of the valve handles to ensure they are in good condition. 2. Ensure the valves are closed and that there are no leaks
13	Grounds	Ensure the transformer and protector have separate grounds to the ground grid or vault ground rod. Do not rely on the mount support to act as a ground for the protector
14	Corrosion Protection	Check for the presence of anodes and the condition of their connections (if anodes are installed). Replace if needed

Network Transformer Form Routine – De-Energized
EMP 6.30-1 Guideline

	INSPECT	INSPECTION ATTRIBUTES
1	Primary Cable	De-energize the primary network cable and ensure it is de-energized
2	Network Protector	Ensure the network protector is in the **Open** position, in manual mode, and locked in order to prevent unintentional operation
3	High Side Switch	Verify the high side switch is closed. On **Carte** transformers, inspect the pin that connects the high side switch handle to the operating shaft. Replace it with a new, solid pin if it shows any signs of corrosion or damage
4	Fluid Sample	Obtain a fluid sample from the transformer and the high voltage switch and replenish the fluids. • Refer to TD202 to ensure compliance with ChemLab requirements. • Record the date and quantity of oil added to the main tank to replenish level in the Network Transformer • Submit the fluid samples for testing
5	Pressure Test	Pressure-test the transformer main tank and the high voltage switch. Slowly pressurize each with nitrogen to 3.0 PSI (or Manufacturer's recommendations). Once stabilized, pressure should remain greater than 2.8 PSI for 30 minutes. • When the test passes, reduce the pressure to 0.5 PSI. • If the test fails, further investigation is required. Notify Supervision

APPENDIX 13

UNDERGROUND NETWORK PROTECTORS

5.29 - Network Protectors (NPs)

1.0 Introduction

1.1 A network protector is an air circuit breaker and relay scheme (network protector mechanism) connected between the secondary side of a network transformer and the secondary network grid. The network protector is designed to perform the following three basic functions.

1.1.1 Open on reverse power (flow of energy from the network into the transformer)

1.1.2 Close on system conditions that allow for power flow into the secondary networks.

1.1.3 Close on a de-energized secondary network.

1.2 Incorporated in the design of the network protector are network protector fuses. These fuses provide backup protection should the network protector fail to open during faults on the primary feeder.

1.3 Network protectors fall under two categories – Live Front and Dead Front designs.

1.3.1 Live Front Network Protectors have exposed energized parts. The live front network protectors require the removal of the network protector fuses and transformer links to rack the breaker mechanism out of the enclosure to perform maintenance activities, (CM22 and MG8/9 styles). This type of network protector utilizes a motor close mechanism to close the network protector contacts.

1.3.2 Dead Front Network Protectors have all energized parts insulated or isolated. This type of protector uses a spring charge, to close the network protector contacts (CMD and CM52 styles). The spring is charged by a motor, which then releases the stored energy to close the protector contacts.

1.4 The maintenance requirements for the following network protectors are provided in separate sections for each model.

1.4.1 CMD

1.4.2 CM-22

1.4.3 CM-52

1.4.4 MG 8/9

NOTE: All specific maintenance requirements that are followed by a triangle symbol "▲" are explained in the Network Protectors Maintenance Basis Documentation section of this chapter.

2.0 Reference Documents

29CFR 1910 OSHA General Industry Regulations

29CRR 1926 OSHA Construction Industry Regulations

C57.12.44-2005 IEEE Standard Requirements for Secondary Network Protectors

NEMA AB-4-2003 NEMA Standards Publication, Guidelines for Inspection and Preventive

Maintenance of Molded Case Circuit Breakers Used in Commercial and Industrial Applications

ANSI C37.50-1989 American National Standard, Switchgear Low Voltage AC Power Circuit Breakers Used in Enclosures – Test Procedures

3.0 Facilities/Equipment

3.1 Street and Spot Networks

4.0 Definitions

4.1 The abbreviations used for the intervals are:

4.1.1 **A/R** = As Required

4.1.2 **CTD** = Capacitive Trip Device

4.1.3 **DTA** = Direct Trip Actuator

4.1.4 **R** = Required

4.1.5 **M** = Month, i.e. 1M = 1 Month

4.1.6 **Y** = Year, i.e. 2Y = 2 Years

5.0 General

5.1 In Table 1, the intersection of the row and column indicate the inspection or maintenance interval for the equipment in the column heading. For example, the interval for a Major Maintenance on the CM-22 is 2Y (or 2 years).

Table 1 – Network Protectors Maintenance Intervals

Network Protector Maintenance Schedule	**Network Protector Type**				
	CMD – DTA or CTD Actuation Section 5		CM-22 Section 6	CM-52 Section 7	MG 8/9 Section 8
	DTA	CTD			
PM Task					
Condition Monitoring					
Any defects found during Routine Inspection, such as worn contacts, rust, failed pressure test, excessive operation count, etc.	A/R	A/R	A/R	A/R	A/R
Time-Directed					
Routine Inspection – Energized ▲	1Y	1Y	1Y	1Y	1Y
Major Maintenance – De-Energized ▲ (Note 3)	2Y **Note 1**	2Y	2Y	4Y (2Y) **Note 2**	2Y
Condition Based					
Major Maintenance – All Models	Counter over 500 Ops since last Annual Inspection				
Failure Finding					

Equipment Failure Reporting System used by your region (EFRS, UPER, Cascade etc.)	R	R	R	R	R
Failure Investigation	A/R	A/R	A/R	A/R	A/R
Scheduling Requirements					
Perform together with Network Transformer Maintenance					

NOTE: 1. Convert all DTA actuators to CTD at the NP's next Major Maintenance (unless the NP is being taken out of service). ▲ Conversion kits with instructions are available: Stock Code 0000446777 for 480 volt CMDs and 0000446778 for 216 volt CMDs.

2. For the CM- 52 Network Protectors, a Major Maintenance shall be considered based upon the number of operations, 2Y after the initial installation date and subsequently every 4Y.

3. For units which are remotely monitored and alarmed on a continuous basis, utilizing SCADA or equivalent, for Pressure, Temperature, Voltage, Current and Oil Level the major maintenance may be extended to a four (4) year frequency.

6.0 CMD Maintenance Categories

6.1 Condition Monitoring

6.1.1 See Section 11

6.2 Time Directed

6.2.1 CMD Routine Inspection – Energized ▲

.1.1. Refer to either EMP Instruction 6.29B or EMP Instruction 6.29BB (EMA) for details

6.2.2 CMD Major Maintenance ▲

.2.1. Refer to either EMP Instruction 6.29B or EMP Instruction 6.29BB (EMA) for details

6.2.3 Failure Finding

3.1. Determine the condition of the aircraft warning lights A failure report shall be completed for any network protector failurein the specific equipment failure reporting system used by each operating company (EFRS, UPER, Cascade, etc.).

3.2. Analysis of network protector failures should be performed when deemed necessary by Distribution Standards.

7.0 CM-22 Maintenance Categories

7.1 Condition Monitoring

7.1.1 See Section 11

7.2 Time Directed

7.2.1 CM-22 Routine Inspection – Energized ▲

.1.1. Refer to either EMP Instruction 6.29DA or EMP Instruction 6.29DB (EMA) for details

7.2.2 CM-22 Major Maintenance ▲

.2.1. Refer to either EMP Instruction 6.29DA or EMP Instruction 6.29DB (EMA) for details

7.2.3 Failure Finding

3.1. A failure report shall be completed for any network protector failure in the specific equipment failure reporting system used by each operating company (EFRS, UPER, Cascade, etc.).

3.2. Analysis of network protector failure should be performed when deemed necessary by Distribution Standards

7.2.4 CM-22 References:

4.1. Richards NP Instruction Manual, Type 313NP, 800 to 3500 Amperes, IM 1223-001B.

4.2. Eaton Network Protector Training Seminar, Handout

4.3. IEEE Standard Requirements for Secondary Network Protectors, IEEE std. C57.12.44-2006

4.4. Richards Manufacturing Network Protector Training Book

4.5. 4.5. Eversource Employee Safety Manual

8.0 CM-52 Maintenance Categories

8.1 Condition Monitoring

8.1.1 See Section 11

8.2 Time Directed

8.2.1 CM-52 Routine Inspection – Energized ▲

.1.1. Refer to either EMP Instruction 6.29AA or EMP Instruction 6.29AB (EMA) for details

8.2.2 CM-52 Major Maintenance ▲

.2.1. Refer to either EMP Instruction 6.29AA or EMP Instruction 6.29AB (EMA) for details

8.2.3 Failure Finding

3.1. A failure report shall be completed for any network protector failure in the specific equipment failure reporting system used by each operating company (EFRS, UPER, Cascade, etc.).

3.2. Analysis of network protector failure should be performed when deemed necessary by Distribution Standards

8.2.4 CM-52 References:

4.1. Eaton, Cutler Hammer, Type CM52 Network Protectors 1875 to 3000A, Instruction Bulletin I.B. 35-552-G

4.2. Eaton Network Protector Training Seminar, Handout

4.3. IEEE Standard Requirements for Secondary Network Protectors, IEEE std. C57.12.44-2006

9.0 MG 8/9 Maintenance Categories

9.1 Condition Monitoring

9.1.1 See Section 11

9.2 Time Directed

9.2.1 MG 8/9 Routine Inspection – Energized ▲

.1.1. Refer to either EMP Instruction 6.29CA or EMP Instruction 6.29CB (EMA) for details

9.2.2 MG 8/9 Major Maintenance ▲

.2.1. Refer to either EMP Instruction 6.29CA or EMP Instruction 6.29CB (EMA) for details

9.2.3 Failure Finding

3.1. A failure report shall be completed for any network protector failure in the specific equipment failure reporting system used by each operating company (EFRS, UPER, Cascade, etc.).

3.2. Analysis of network protector failure should be performed when deemed necessary by Distribution Standards

9.2.4 MG 8/9 References:

4.1. Richards NP Instruction Manual, Type 313NP, 800 to 3500 Amperes, IM 1223-001B.

4.2. GE Network Protector Maintenance Manual, MG8 Network Protector

4.3. Eaton Network Protector Training Seminar, Handout

4.4. IEEE Standard Requirements for Secondary Network Protectors, IEEE std. C57.12.44-2006

10.0 Network Protectors Maintenance Basis Documentation

10.1 The maintenance activities and their schedules are based on industry experience, manufacturer's recommendations, and recommendations from the Maintenance Standardization Working Group (representing all three operating companies), and the subject matter expert. Specific determinations are provided for each of the four NP types.

Table 2 – CMD Maintenance Activity Basis

Requirement	Basis
Perform a 1-Year Routine Inspection - Energized.	The manufacturer recommends a Major Maintenance at this interval, but an annual Routine Inspection has been proven to find minor defects before they affect protector performance.
Perform a 2-Year Major Maintenance.	The Mfr recommends a 1-Year Major Maintenance interval, but many years of historical data have proven that a 2-Year Major Maintenance interval provides acceptable equipment performance.

Perform Insulation Resistance Test of the NP mechanism only.	The manufacturer recommends performing dielectric tests as described in Bulletin I.B. 35-500-1E on the enclosure and the NP mechanism. Performing dielectric tests on the transformer bus and network bus within a network protector enclosure is impractical in the field due to the fact that the enclosure bus (network and transformer) would have be isolated from the network secondaries and transformer secondary terminals. The Eaton Network Protector Training Seminar indicated that an insulation resistance test should be performed on the network protector mechanism to indicate the condition of the insulating material in the protector. Insulation resistance tests have recently been implemented at Eversource and have identified a number of easily correctable conditions helping to improve reliability of the protectors.
Adjust contact pressure 1 month after initial installation.	The mechanism GPO-3 structure will relax and may result in a change of contact pressure, causing the protector not to open completely. This is recommended by the manufacturer. No new installations of the CMD NP are planned at this time.
Check the operations counter 1 month after initial installation at time of the contact pressure check.	The manufacturer recommends a check of the operations counter 30-90 days following initial installation. The operations counter can indicate if the protector is operating excessively. The 1 month interval is satisfactory and saves the second post-installation inspection. No new installations of the CMD NP are planned at this time.
Replace all CMD DTA actuators with Capacitor Trip Device (CTD) at 1st Major Maintenance following their identification.	The manufacturer recommends this retrofit to improve reliability of the Network Protector. DTA actuators have a failure history with Eversource and at least one other utility. CTD actuators are proven to be more reliable.
Perform a Major Maintenance if the protector has operated over 500 times in an year.	A high number of network protector operations may indicate a problem with the network protector, requiring maintenance, relay adjustment, etc. The majority of network protectors relays installed at Eversource are electromechanical relays. Electromechanical relay setpoints are known to change over time and may require adjustment to ensure proper operation of the network protector. This requirement ensures that the relays are operating correctly and are properly adjusted for system conditions.

Table 3 – CM-22 Maintenance Activity Basis

Requirement	Basis
Perform a 1-Year Routine Inspection - Energized	The manufacturer recommends a Major Maintenance at this interval, but based on Eversource's operating experience, an annual Routine Inspection has been proven to find minor defects before they affect protector performance.
Perform a 2-Year Major Maintenance.	The Mfr recommends a 1-Year Major Maintenance interval, but many years of historical data have proven that a 2-Year Major Maintenance interval provides acceptable equipment performance.
Perform Insulation Resistance Test of the NP mechanism only.	The manufacturer recommends performing dielectric tests as described in Bulletin I.B. 35-500-1E on the enclosure and the NP mechanism. Performing dielectric tests on the transformer bus and network bus within a network protector enclosure is impractical in the field due to the fact that the enclosure bus (network and transformer) would have to be isolated from the network secondary and transformer secondary terminals. The Eaton Network Protector Training Seminar indicated that an insulation resistance test should be performed on the network protector mechanism to indicate the condition of the insulating material in the protector. Insulation resistance tests have recently been implemented at Eversource and have identified a number of easily correctable conditions helping to improve reliability of the protectors.

Perform a Major Maintenance if the protector has operated over 500 times in an year.	A high number of network protector operations may indicate a problem with the network protector, requiring maintenance, relay adjustment, etc. The majority of network protectors relays installed at Eversource are electromechanical relays. Electromechanical relay setpoints are known to change over time and may require adjustment to ensure proper operation of the network protector. This requirement ensures that the relays are operating correctly and are properly adjusted for system conditions.

Table 4 – CM-52 Maintenance Activity Basis

Requirement	Basis
Perform a 1-Year Routine Inspection - Energized.	This is based on the manufacturer's recommendation and company experience.
Perform Major Maintenance on a 4-Year interval.	The manufacturer recommends a 5-Year interval for Major Maintenance. The first Major Maintenance is performed 2Y after installation to ensure it was properly installed. After that, the 4-Yr cycle allows us to better coordinate maintenance scheduling with other system maintenance.
Perform Insulation Resistance Test of the NP mechanism only.	The manufacturer recommends performing dielectric tests as described in Bulletin I.B. 35-500-1E on the enclosure and the NP mechanism. Performing dielectric tests on the transformer bus and network bus within a network protector enclosure is impractical in the field due to the fact that the enclosure bus (network and transformer) would have to be isolated from the network secondary and transformer secondary terminals. The Eaton Network Protector Training Seminar indicated that an insulation resistance test should be performed on the network protector mechanism to indicate the condition of the insulating material in the protector. Insulation resistance tests have recently been implemented at Eversource and have identified a number of easily correctable conditions helping to improve reliability of the protectors.
Perform a Major Maintenance if the protector has operated over 500 times in an year.	A high number of network protector operations may indicate a problem with the network protector, requiring maintenance, relay adjustment, etc. The majority of network protectors relays installed at Eversource are electromechanical relays. Electromechanical relay setpoints are known to change over time and may require adjustment to ensure proper operation of the network protector. This requirement ensures that the relays are operating correctly and are properly adjusted for system conditions.

Table 5 – MG 8/9 Maintenance Activity Basis

Requirement	Basis
Perform a 1-Year Routine Inspection - Energized	Richards Mfg recommends cycle count checks at 24 hours, 48 hours, 1 week, 1 month, 6 months and yearly following initial installation. Based on experience, it has been determined that annual inspections are adequate for detecting excessive cycling.
Perform a 2-Year Major Maintenance.	The Mfr recommends a 1-Year Major Maintenance interval, but many years of historical data have proven that a 2-Year Major Maintenance interval provides acceptable equipment performance.
Perform insulation resistance tests	Richards Mfg NP instruction Manual, Type 137, IM 1224-001A indicates hi-pot testing is not required on MG8/9 NPs. However, CL&P has been performing insulation resistance testing on MG8/9, CM22 and CMD style protectors and have found that insulation resistance testing (Megger) has identified a number of degraded conditions, including degraded arc chutes, and backboards. Repair of these conditions helps to maintain a safe and reliable system.

Perform a Major Maintenance if the protector has operated over 500 times in an year.	A high number of network protector operations may indicate a problem with the network protector, requiring maintenance, relay adjustment, etc. The majority of network protectors relays installed at Eversource are electromechanical relays. Electromechanical relay setpoints are known to change over time and may require adjustment to ensure proper operation of the network protector. This requirement ensures that the relays are operating correctly and are properly adjusted for system conditions.

11.0 Failure Findings

11.1 Failures of network protectors shall be documented in the equipment failure reporting system used by the individual operating companies (EFRS, UPER, Cascade, etc.).

11.2 Analysis of a failed network protector may be performed as deemed necessary by Distribution Standards.

12.0 Condition-Based Monitoring

12.1 Condition-based maintenance can be developed if additional monitoring of the network protector is implemented. This may help to lengthen current maintenance intervals beyond the current cycles. The Cutler Hammer MPCV network protector relays, which are installed in the CM-52 network protectors, have communication capability built in, that can be adapted to and monitored by the SCADA system. The CM-52 network protectors were specified with a pressure switch to indicate a loss of pressure within the submersible enclosure. This can trigger a condition-based maintenance activity and allow the unit to be repaired shortly after the defect occurs, as opposed to letting sit un-repaired for the remainder of its inspection interval. This could protect the unit from further damage and add to the reliability of the network.

12.2 Many Utilities have dedicated feeders supplying only their secondary networks. In a dedicated network system, the operation of network protectors can be verified by de-energizing a single network feeder to determine if all network protectors open. This can provide an indication that the network protectors are operational, which may, with other improvements, be able to extend the maintenance cycle. Northeast Utilities has added radial loads off of the network feeders, thus creating non-dedicated network feeders. Nondedicated network feeders would require significant switching to be able to deenergize a feeder to check the operation of network protectors. As such feeders supplying networks would need to be reconfigured to create a dedicated network to facilitate this operational check.

12.3 Many parameters can be monitored to develop condition-based maintenance including the following:

12.3.1 Network protector pressure

12.3.2 Transformer voltages

12.3.3 Phase angle

12.3.4 Pumping/Counter

12.3.5 Sump pump alarm

12.3.6 Network voltages

12.3.7 Protector currents

12.3.8 Protector status (open or closed)

12.3.9 General trouble alarm

12.3.10 Protector temperature

6.29 – Network Protector – Routine Inspection - Energized

Purpose

The Purpose of this inspection is to identify any potential operational problems with Network Protectors prior to their major maintenance cycle. This inspection is intended to be performed with the network protector door closed.

CAUTION

1. No modifications to network protectors shall be made, either temporary or permanent, without prior approval of the Distribution Engineering Department
2. Stop the job, place equipment in a safe condition, and contact Supervision if the process does not proceed as expected, if unusual situations occur during the performance of the process, or any significant problems occur during maintenance activities.

Before You Begin

Prior to assigning work on network protectors, Supervision shall:

1. Prior to assigning personnel to perform “Work” on a network protector, ENSURE the person(s) responsible for performing the “Work” is fully qualified in accordance with operating company requirements
2. Ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
   - TD 211, “When to Wear FR Clothing”
   - TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut and Western Mass only)
   - TD 955, “Confined Space Requirements”
   - Eversource Employee Safety Manual
   - TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (Connecticut ONLY)
3. Ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
   - Safety Glasses with side shields
   - EH (Electrical Hazard) rated boots
   - High Voltage gloves
   - FR (flame resistant) clothing, as specified in TD 211
4. Whenever “Work” is performed on a network unit as defined in paragraph 5 of this procedure, the following PPE is required :
   - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or company approved equivalent.
   - Safety glasses with side shields
   - Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)
   - Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall)
5. All persons performing “Work” on Network Units as defined below and those persons within the immediate work zone while “Work” is being performed shall wear at minimum double layer full body FR clothing, minimum 25 cal. FR rated hood (beehive type with built-in arc rated face shield), safety glasses and, minimum of low voltage (Class 0) rubber gloves (high voltage rubber gloves preferred). As defined in this document, “Work” includes the following tasks:
   - Installing or removing transformer links and network fuses

- Rolling or racking out the protector
- Phasing the unit
- Connecting test leads to an energized bus
- Obtaining transformer and network voltages
- Test probe usage prior to installing links and network fuses
- Or any other work performed inside the network protector enclosure with the transformer and/or network bus energized

6. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
    - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to Connecticut and Western Mass)
    - If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
    - The deficiencies described below, require the primary circuit to be de-energized in accordance with the operating policy.
        - o Major maintenance not performed within the maintenance cycle required by the Eversource Maintenance Program
        - o Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level
        - oAny other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage / corrosion in the network protector or other defect that requires immediate repair to return to service.
7. For cases where multiple network transformers exist in a vault, it will generally not be possible to de-energize all of those units for a variety of reasons. Therefore, prior to working on a network transformer, where multiple network transformers exist in a vault, maintenance records shall be reviewed for major deficiencies and/or major maintenance completion within the maintenance cycle per the Eversource Maintenance Program prior to working in the vault.
    - If records indicate that major maintenance for all transformers within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
    - If major deficiencies or major maintenance was not completed, management will jointly work with employees for the appropriate steps to follow.

8. With the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro-filling) is being performed.
    - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
9. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.
10. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
11. Supervision shall ensure the assigned workers have primer, paint, and any additional material needed for cleaning and preservation of the exterior of the network protector prior to departing the work center.
12. Prepare the vault for entry.
    - Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment
    - Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    - Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Procedure

1. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions). These may be in sections of the manual other than with the instructions.
2. Prepare the vault for entry.
    a) Check for dangerous atmospheric conditions before entering the vault.
    b) Ventilate the vault, if required, in accordance with the Accident Prevention Manual.
    c)Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements.
3. Clean the exterior of the network protector to facilitate inspection and maintenance of the network protector. Cleaning shall include:
    a) Removing debris from the top of the enclosure.
    b) Cleaning all outside surfaces of the enclosure to facilitate corrosion inspection and internal inspections through the network protector enclosure windows.
    c) Check High and Low side grounds.
    d) Check the ground connection between the network protector ground pad and the transformer ground pad.

NOTE
When painting is required, use proper ventilation and respiratory equipment.

4. Inspect the network protector enclosure for chipped, cracked or missing paint, corrosion, etc. Remove any loose paint and/or rust with a wire brush and repaint those areas to prevent further corrosion.
5. Inspect the interior of the network protector through the enclosure door windows for abnormal conditions including but not limited to the following:
   - Signs of moisture
   - Blown fuses
   - Signs of arcing or soot
   - Noisy operation of any electro-mechanical relays
   - Network protector relay failure
     - o Check the condition of electro-mechanical relays, when possible.
     - o ETI relays have a scrolling alphanumeric LED display. An ETI relay with no scrolling display indicates a failed relay.
     - o MPCV relays have three lights: **Fail**, **Float**, and **Trip and Close**. A failed relay will have the **Fail** light lit.
6. Record the current value on the operations counter. If the number of operations is greater than 500 since the last inspection, notify Supervision.
7. **For CM-52 network protectors only**, verify that all IDM (Indicating Diagnostic Module) LEDs are illuminated. See Figure 1.



Figure 1 – The IDM Module

Yellow “Power On”	Indicates the presence of normal power input to the IDM.
Yellow “Motor OK”	Indicates a healthy motor and close circuit.
Red “Motor Enabled”	Indicates that the supply voltage is at or above 73% of nominal and the motor has sufficient power to charge the breaker.
Yellow “IDM Trip Enabled”	Indicates that the IDM trip portion of the circuit is healthy and is ready to implement a trip, if such conditions should exist.

- If the LED is illuminated, the component is in working order.
- If the LED is not illuminated, the component or the wiring to the component is damaged.

CAUTION

For 480 volt network protectors, If the network protector is closed, **and** there is an exposed, energized copper bus or conductors, ***do not*** check for blown limiters or phase currents as required by steps 8 & 9.

8. Inspect for blown limiters, if applicable, as follows (**all protectors**):
   a) Determine if the network protector is open or closed.
      - o If the network protector is **open**, record this on the inspection form and continue to Step 9.
      - o If the network protector is **closed**, inspect for blown limiters by using a clamp on current transformer (CT) around each individual secondary cable.
   - If the ammeter reads current, the limiter is good.
   - If the limiter is open, record this condition and alert supervision of the need for corrective action.

NOTE

A blown limiter on the network protector secondary terminals may indicate a damaged or defective secondary cable that needs to be replaced.

9. Check and record the phase currents on each phase as follows:
   a) Determine if the network protector is **open** or **closed**.
      - o If the network protector is **open** go to step 10.
      - o If the network protector is **closed**, check and record current readings using one of the following methods:
   - Measure current on each phase using a rope style current transformer around all conductors of each phase.

     or
   - If an ETI relay is installed, read phase currents from the scrolling display on the relay.
10. Verify the protector enclosure is holding pressure using a pressure gauge/fill device.
    - If there is positive pressure, it indicates the protector is air-tight. Go on to the next step.
    - If it is not, perform a **leak check** on those network protectors with submersible enclosures as follows:
      a) Pressurize the enclosure with 5 PSI of dry nitrogen.
      b) Apply a soap solution to the door gaskets, enclosure penetrations, throat gaskets, operating handle gaskets, welds, etc.
      c) Let this sit for 10 minutes.
      d) Check for leaks by looking for soap bubbles. Fix any leaks if possible.
      e) Record any leaks on the inspection form and alert supervision.
      f) Reduce the pressure within the enclosure to 1.5 PSI.

	INSPECT	INSPECTION ATTRIBUTES
1	Clean the exterior of the network protector	• Removing debris from the top of the enclosure. • Clean all outside surfaces of the enclosure to facilitate corrosion inspection and internal inspections through the network protector enclosure windows.
2	Check Ground Connections	• Check High and Low side grounds. • Check the ground connection between the network protector ground pad and the transformer ground pad.
3	Inspect the network protector enclosure	Inspect the network protector enclosure for chipped, cracked or missing paint, corrosion, etc. Remove any loose paint and/or rust with a wire brush and repaint those areas to prevent further corrosion
4	Inspect the interior of the network protector	Through the enclosure door windows check for abnormal conditions, including but not limited to the following: • Signs of moisture • Blown fuses • Signs of arcing or soot • Noisy operation of any electro-mechanical relays
5	Network Protector Relay	Check the condition of electro-mechanical relays, when possible. • ETI relays have a scrolling alphanumeric LED display. An ETI relay with no scrolling display indicates a failed relay. • □ MPCV relays have three lights: Fail, Float, and Trip and Close. A failed relay will have the Fail light lit
6	Operations Counter	Record the current value on the operations counter. If the number of operations is greater than 500 since the last inspection, notify Supervision
7	Indicating Diagnostic Module	For CM-52 network protectors only, verify that all IDM (Indicating Diagnostic Module) LEDs are illuminated • If the LED is illuminated, the component is in working order. • If the LED is not illuminated, the component or the wiring to the component is damaged
8	Inspect Limiters	Inspect for blown limiters, if applicable, as follows (all protectors): Determine if the network protector is open or closed. • If the network protector is open, record this on the inspection form and go to step 10. • If the network protector is closed, inspect for blown limiters by using a clamp on current transformer (CT) around each individual secondary cable. O If the ammeter reads current, the limiter is good. O If the limiter is open; record this condition and alert supervision of the need for corrective action.
9	Phase Currents	Check and record the phase currents on each phase as follows: If the network protector is closed, check and record current readings using one of the following methods: • Measure current on each phase using a rope style current transformers around all conductors of each phase. • If an ETI relay is installed, read phase currents from the scrolling display on the relay.
10	Leaks	Verify the protector enclosure is holding pressure using a pressure gauge/fill device. • If there is positive pressure, it indicates the protector is air-tight. . • If it is not, perform a leak check on those network protectors with submersible enclosures per NUMM 6.29

6.29A - CM-52 Network Protectors – Major Maintenance

CAUTION

1. No modifications to network protectors shall be made, either temporary or permanent, without prior approval of the Distribution Engineering Department.
2. Stop the job, place equipment in a safe condition, and contact Supervision if the process does not proceed as expected, if unusual situations occur during the performance of the process, or any significant problems occur during maintenance activities.

Before You Begin

Prior to assigning work on network protectors, Supervision shall:

1. That person(s) responsible for performing the “Work” are properly trained and fully qualified in accordance with operating company requirements..
2. That all PPE and safety requirements are met, including but not limited to those defined within the following documents:
    - TD 211, “When to Wear FR Clothing”
    - TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut, and Western MA only)
    - TD 955, “Confined Space Requirements”
    - Eversource Employee Safety Manual
    - TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (Connecticut ONLY)
3. That person(s) responsible for performing the “Work” are aware of the following PPE requirements whenever working in Underground Vaults & Manholes:
    - Hard Hats
    - Safety Glasses with side shields (or Goggles)
    - EH (Electrical Hazard) rated boots
    - Low and High Voltage gloves
    - FR (flame resistant) clothing, as specified in TD 211
4. That person(s) responsible for performing the “Work” on Network Units as defined in paragraph 4.1 below and those person(s) within the immediate work zone, shall at minimum wear the following PPE (Identified in JHA-2013-03)::
    - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or 45 Calorie Rated Knit Hood with Goggles (Stock Code 0457052) or, company-approved equivalent.
    - Safety glasses with side shields (or Goggles)
    - Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)
    - Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall). Total FR calorie count must be equal to or greater than 16 calories.

4.1 Work” on Network Units requiring PPE, identified in paragraph 4, includes the following activities:

- Installing or removing network fuses
- Rolling or racking out/in the breaker (operating mechanism cassette protector)(Except when using remote racking mechanism with control pendant)

- Phasing the unit at the network secondary buses (network fuses removed and breaker closed)
- Connecting test leads to an energized bus (Note: Always re-install compartment access shield after test leads are connected)
- Obtaining transformer and network voltages on secondary buses
- Installing or removing horizontal or vertical barrier boards, after the breaker is racked out to the “Disconnect” position, and fully drawn out.
- Any other work performed inside the network protector enclosure with the transformer and/or network bus energized prior to installation of the horizontal and vertical barrier boards.

Note: No breaker work is to be performed while the breaker is in “Test” or “Connect” positions.

5. That once the appropriate horizontal and vertical barrier boards are installed, person(s)responsible for performing the “Work” on Network Units as defined in paragraph 5.1 below and those person(s) within the immediate work zone shall at minimum wear the following PPE (Identified in JHA-2013-03):
   - Hard Hat
   - Full body FR clothing where the total FR calorie count must be equal to or greater than 8 calories
   - Safety Glasses with Side Shields (or Goggles)
   - Work gloves as needed

5.1 Work” on Network Units requiring PPE, identified in paragraph 5, includes the following activities:
   - Lowering or raising equipment and tools.
   - Maintenance, Testing and Calibration of the breaker (To perform work on the breaker, the breaker has to be racked out to the “Disconnect” position)
   - Wiring changes outside the energized area

6. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
   - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to Connecticut and Western MA)
   - If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
   - The deficiencies described below, require the primary circuit to be de-energized in accordance with the operating policy.

- o Major maintenance not performed within the maintenance cycle required by the Eversource Maintenance Program
- o Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level
- o Any other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage/ corrosion in the network protector or other defect that requires immediate repair to return to service.

NOTE: The secondaries remain energized to the protector enclosure unless existing deficiencies or conditions require that the secondaries be cut as jointly determined by Management and Field Personnel.

7. That prior to accessing manholes and vaults to investigate, inspect or work on network units where multiple network units exist in a vault, the maintenance records will be reviewed for condition of the units, major deficiencies and/or major maintenance completion within the maintenance cycle per the Eversource Maintenance Program.
   - If records indicate that major maintenance for all network units within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
   - If major deficiencies exist or major maintenance was not completed, management will jointly work with Field Personnel for the appropriate steps to follow.
   - If any units within the vault have deficiencies, the primaries for the unit being worked on must be de-energized.

NOTE: For cases where multiple network units exist in a vault, it will generally not be possible to de-energize multiple units for a variety of reasons. Further actions will be determined jointly by Management and Field Personnel.

8. That with the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro- filling) is being performed.
   - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
9. That primaries are de-energized and grounded at every network transformer and/or protector whenever installing or replacing a network transformer or protector.
10. That Job Setup is performed. This may include working with local authorities to establish Work zones, determining requirements for various jobs, and switching requirements. All arrangements should be completed and set up prior to beginning the job, which include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.

11. Review of the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
12. That person(s) responsible for performing the "Work" have primer, paint, and any additional material needed for cleaning and preservation of the exterior of the network protector prior to departing the work center
13. That person(s) responsible for performing the "Work", prepare the vault for entry.
    - Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment.
    - Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    - Remove substantial water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Network Protector Tools

The following fully insulated tools are available and may be useful for Network Protector Service:

Tool Description	NU Stock Code
Wrench, Torque, 1/2" drive	0441650
Wrench, Socket, extension bar, 1/2" drive, 12" long	0441649
Socket size 3/4", 1/2" drive, 6 pt.	0441652
Wrench, Socket, T Handle, 33" long, ¾" socket	0441647
MPCV Relay Programmer	0445902
Transformer Mating Gasket For CM52 Size: 800A – 2000A	0450826
Transformer Mating Gasket For CM52 Size: 2500A – 3500A	0450825
CM52-H-1 – Horizontal Barrier Board for CM52 Size: 800A-1875A	0461714
CM52-V-1 – Vertical Barrier Board for CM52 Size: 800A-1875A	0461715
CM52-H-2 – Horizontal Barrier Board for CM52 Size: 2000A-3000A	0461716
CM52-V-2 – Vertical Barrier Board for CM52 Size: 2000A-3000A	0461718
CM52-V-3 – Vertical Barrier Board for CM52 Size: 3500A	0461719

The above listed wrenches may be available in other lengths by special order. The insulation from the time of original manufacture has been increased at the request of Eversource and stock code revisions will reflect "FI" for "Fully Insulated".

NOTE: The orange surface insulation on these tools has a yellow undercoat. If yellow is detected on the surface due to cuts or punctures, the surface insulation has been compromised and the tool should be retired.

Opening the Network Protector Door

NOTE: The CM-52 Network Protector is a dead-front, rack in breaker and does not require the removal of fuses under normal maintenance activities. Testing of the CM-52 network protector should be performed with the breaker racked out to provide a visible break.

1. Vent the protector enclosure as follows:
    - Loosen the enclosure cover bolts on the side opposite from the operating handle in order to vent the protector.

2. Operate the network protector handle while standing to the side of the enclosure or as far away as possible from the front of the enclosure. Leave the handle in the "**OPEN**" position.
3. Verify that the network protector mechanism is in the **open** position as follows:
    - Inspect the network protector position indicator through the network protector enclosure window.
    - Use a clamp or rope style current transformer (CT) around the conductors of each phase, verify that the current on each phase is zero. (Zero current may indicate that the breaker position is open or the network protector fuses or cable limiters are blown.)
    - Measure and record the secondary voltages.
4. Loosen all enclosure cover bolts and pull the bolts back all the way and open the enclosure door. **NOTE**: Be sure the bolts are away from the hinge when opening the door to prevent them from being damaged.

Racking Out and Isolating the Protector

Reminder: Although it is not shown in some of the following figures, proper PPE must be worn while performing maintenance and testing on all Network Protectors.

1. Remove the levering crank mounted on the inside of the enclosure door. See Figure 1.

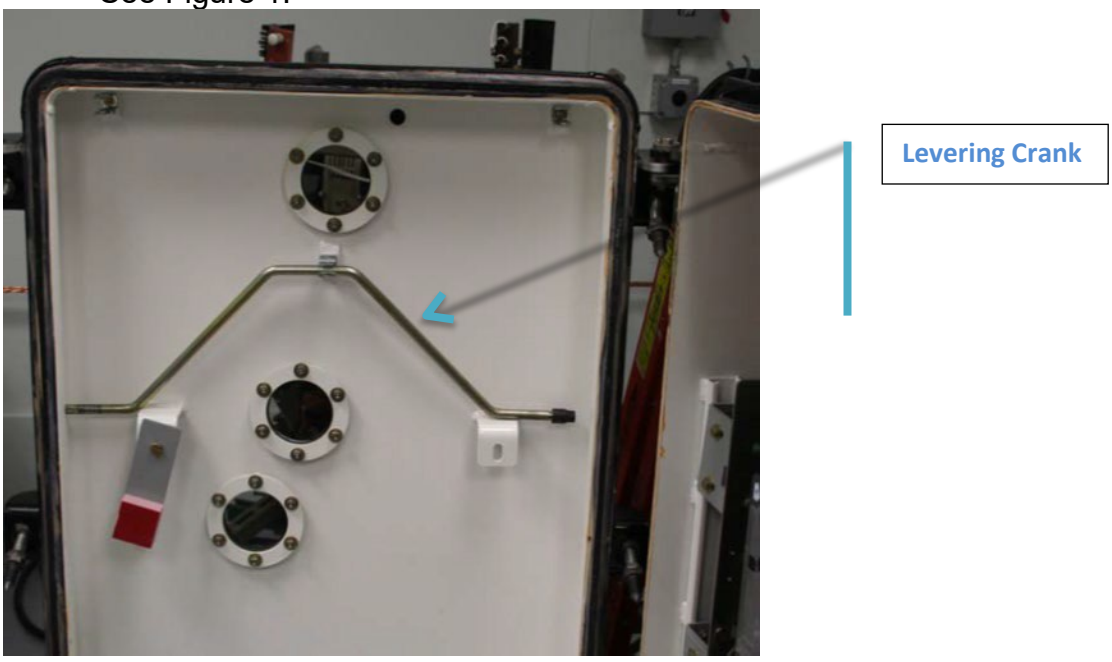


Figure 1 – The Levering Crank

2. Lift the levering crank access door and insert the end of the levering crank (3/8" square). See Figure 2. **NOTE**: 480 volt units may have remote racking requiring a different technique.



Figure 2 – The Levering Crank Access Door

3. Turn the levering crank counter-clockwise.
    - The red window on the breaker will move from the **Connect** position to the **Test** position. See Figure 3.



Figure 3 – The Test Position Indicator

    - The breaker will drop down slightly as it disconnects from the transformer and the network side bus work.
    - If the springs are charged, they will discharge as the breaker is racked out.
    - A full yellow position indicates that the breaker is disconnected from the Network and Transformer side bus.
4. Continue to crank until the crank stops. The green window will indicate that the unit is in **Disconnect** position. See Figure 4.



Figure 4 – The Disconnect Indicator

5. Locate the rail handles on each side of the breaker and pull the breaker evenly until it is completely drawn out.

6. Insert the appropriate “Horizontal” barrier board under the breaker as shown in figure 5. **NOTE**: This step is applicable to CM52 enclosure sizes: 800A-1875A and 2000A-3000A. See Network Protector Tool Table.

Figure 5



Figure 6 – Installing the Horizontal Barrier Board

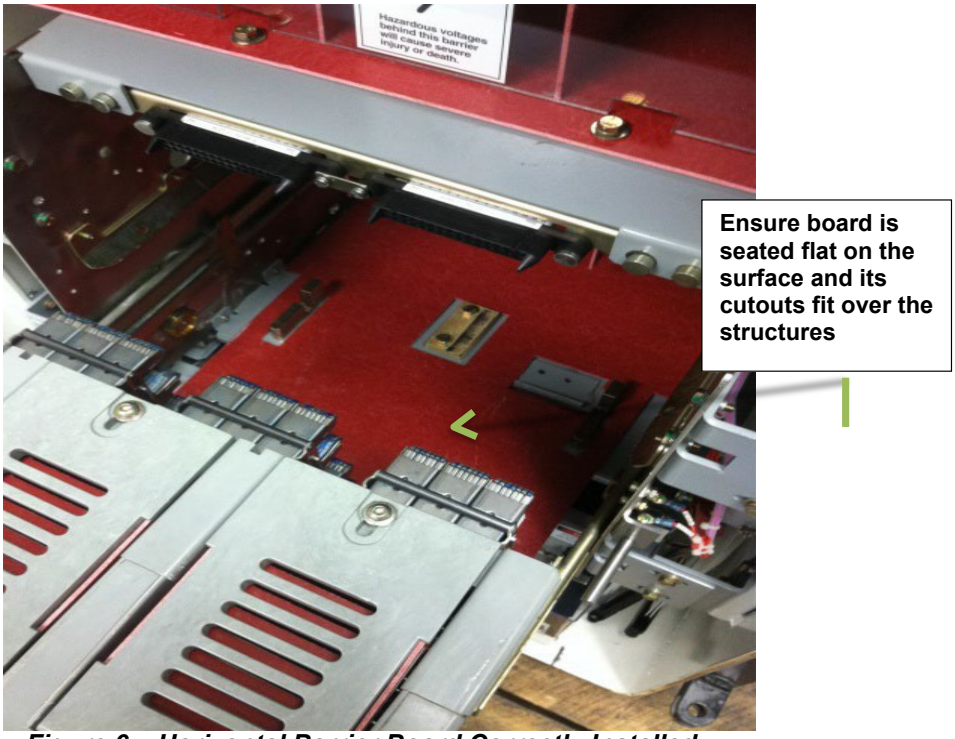


Figure 6 – Horizontal Barrier Board Correctly Installed

7. Install the appropriate “Vertical” barrier board behind the breaker as shown in figure 7. The cutouts near the top of the board should rest on the sides of the enclosure frame, just behind the breaker. **NOTE**: This step applies to all CM52 enclosure sizes. See Network Protector Tool Table.

Figure 7



Figure 7 – Installing the Vertical Barrier Board



Figure 8 – Vertical Barrier Board Correctly Installed

8. Insert the 10mm socket on the crank and remove the front cover bolts. See Figure 9.

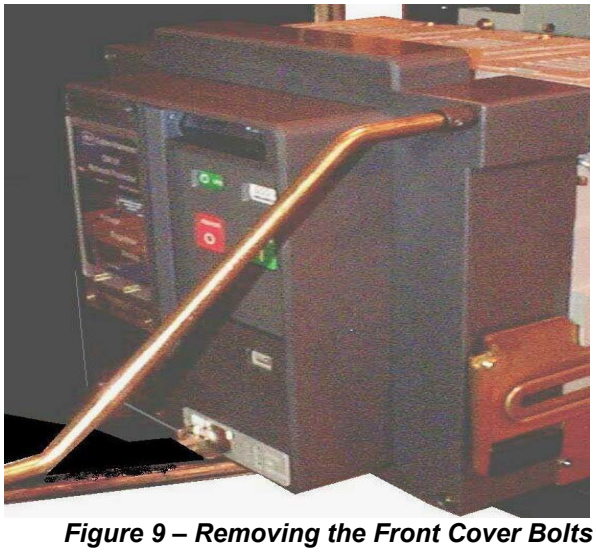


Figure 9 – Removing the Front Cover Bolts

Caution: To prevent the protector from tipping forward, place your hand on the center arc chute to steady breaker mechanism.

9. Pull down slightly on the charge handle and remove the cover.

Inspection of Arc Chutes and Contacts

10. Remove the arc chutes and inspect them to ensure the vents are free and clear. See Figure 10.



Figure 10 – The Arc Chutes

Caution: To prevent the protector from tipping forward, place your hand on the center arc chute to steady breaker mechanism.

11. Manually charge the breaker with the charge handle. See Figure 11.



Figure 11 – Charging the Breaker

- The flag will indicate “Charged” after the closing spring is compressed.

12. Push the button labeled “CLOSE” to close the breaker. See Figure 12.
Note: If there is a plastic shield which covers the close button, carefully remove the hinged cover and remove and discard the plastic shield and reinstall the hinged covers.

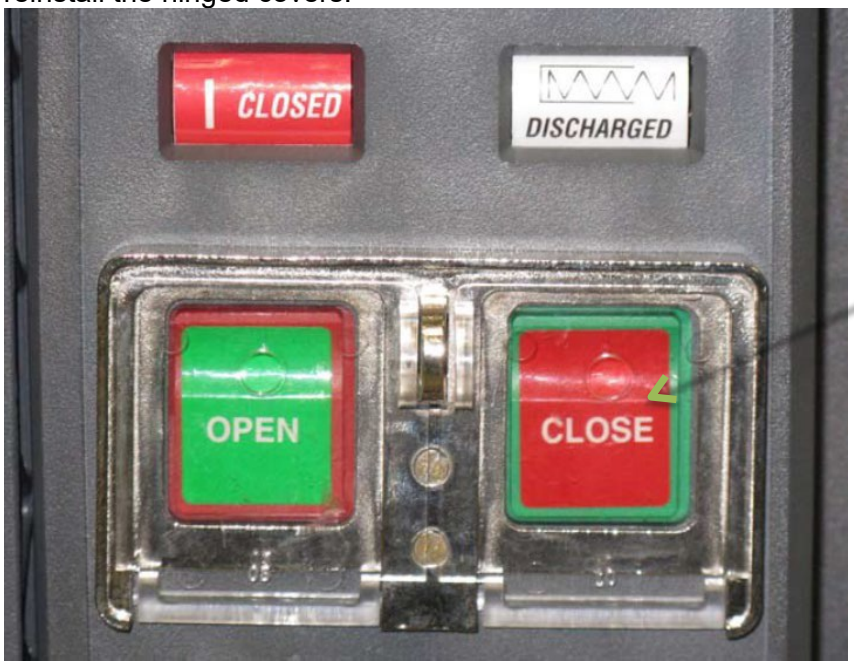


Figure 12 – The “CLOSE” Button

13. Check for contact wear. Side-by-side ledge acts as a contact wear indicator. Check the wear indicator by looking straight down into the arc chamber. See Figure 13.
    - If the ledge is covered by the back edge of the moving contacts, the contacts are in good condition.
    - If the ledge is not completely covered by the back edge of the moving contacts, replace the contacts.

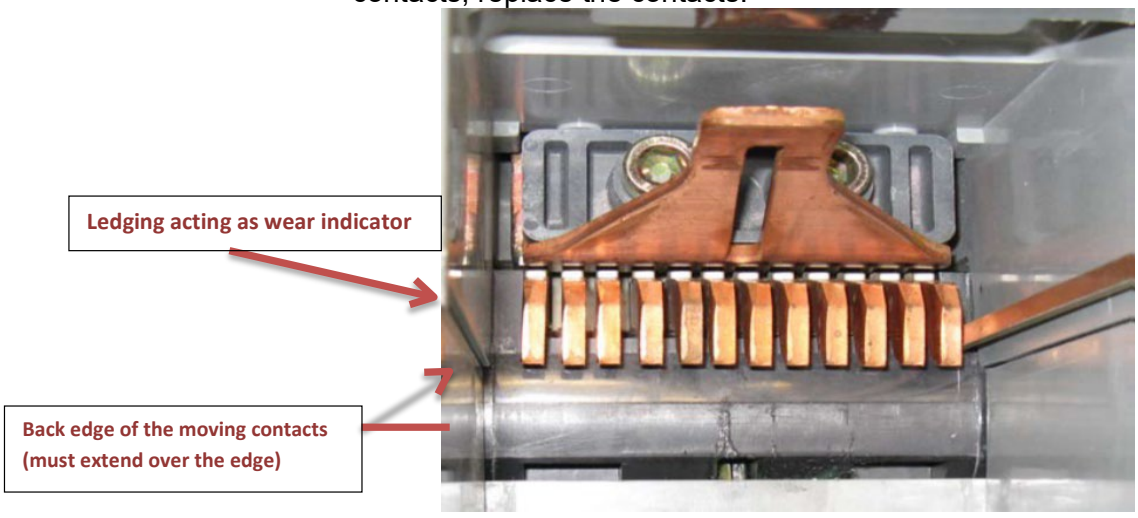


Figure 13 – Checking for Contact Wear

NOTE: There are no adjustments needed for contact pressure or lubrication required. Do not wipe away or add any grease or lubricant.

14. Push the button labeled “OPEN” to open the breaker.
15. Dress the arc contacts if there is black carbon residue from arcing, using only Scotch Brite. Do not use a file on the contacts.

Internal Visual Inspection:

1. Record the counter reading.
2. Check for any signs of liquid entry into enclosure, transformer throat, etc.
3. Check for indication of overheating.
4. Inspect the condition of the wiring. Look for frayed or damaged wires.

Test Sequence:

The next section is a series of tests defined to ensure proper operation at normal condition and at fault duty. It is important to perform the following tests in *this* order:

1. Manual Breaker Operation Test
2. Relay Testing
3. Ground Fault Test (480V Unit Only) (Account Executive to coordinate with Customer contact)

Test 1 – Manual Breaker Operation Test

Caution: To prevent the protector from tipping forward, place your hand on the center arc chute to steady breaker mechanism.

1. Operate the breaker manually while it is on rails by charging the breaker using the charging handle.
2. Once charged, press the CLOSE button.
3. rip the breaker by pressing the TRIP button. Repeat these steps 5 times.

Relay Testing - Please see the following Relay Test Section for testing procedure.

Preparation for Tests 2 through 4

Caution: Test for zero voltage on the potential studs on the test switch as follows:

1. Use a Multi-meter to check for voltage on the stud positions labeled: See Figure 11.
    - N1, N2, N3 (See Figure 11.)
    - T1, T2, T3 (See Figure 11.)



Figure 14 – The Test Switch Phasing Block

2. Ensure that ZERO volts are present.

Reminder: Proper PPE must be worn while attaching leads to an energized bus.

3. Attach Test Set grounds and jumper between the shutter and the cassette frame. See Figure 12.



Figure 15 – Attaching the Test Set Grounds

4. Connect test kit leads N1, N2, N3 and T1, T2, T3 on the studs of the test block.
5. Remove the dead front upper compartment cover. See Figure 13.

NOTE: The fuse links shown in Figure 13 may differ from those used at your location.

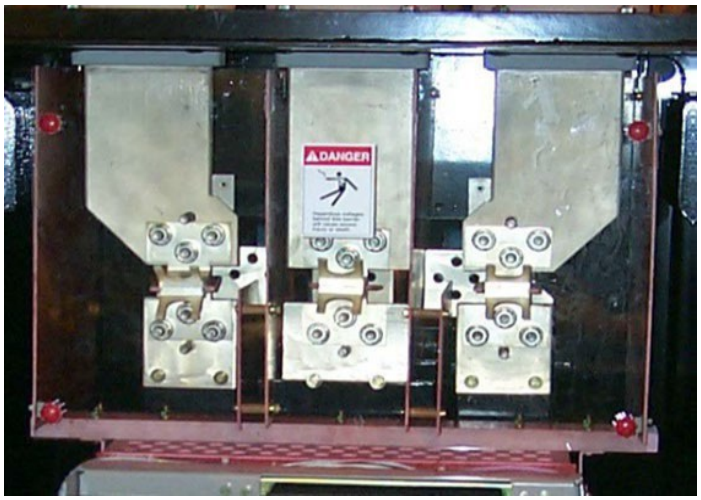


Figure 16 – The Dead Front Upper Compartment

6. Connect the power leads of the Test Set to the energized network bus.
7. Place the outside handle in the AUTO position.

8. Pull the Electrical Interlock forward until the spring detent ball is in front of the Interlock bracket. See Figure 14.

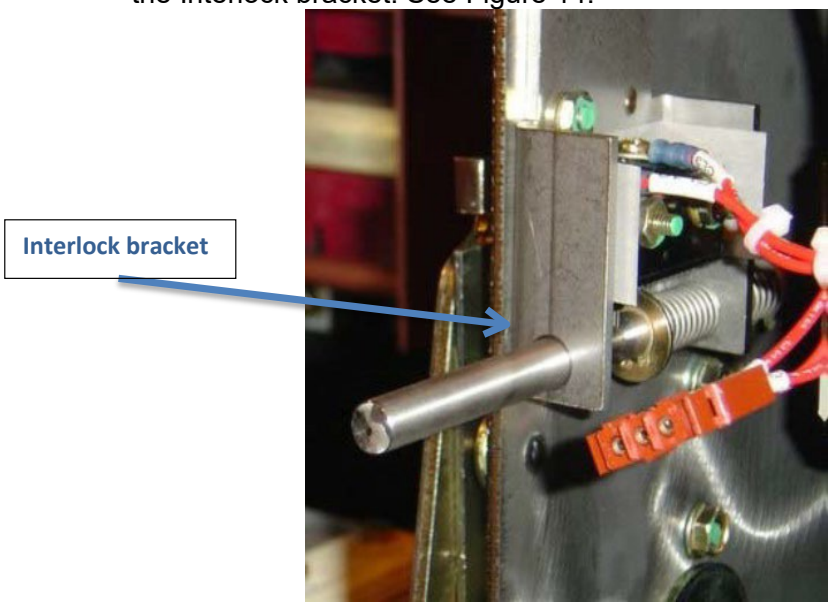


Figure 17 – The Electrical Interlock

9. Test in accordance with the Microprocessor relay tests.

Test 2 – Relay Tests

1. Replace the breaker cover.
   a) Push slightly down on the charging handle and insert the handle through the cover slot.
   b) Tighten the bolts using a cross pattern. Being careful not to overtighten bolts or the cover may crack.
2. Relay Testing will be performed with the breaker out on the rails and **not** with the breaker in the relay test position.
3. Connect the jumper cables between the breaker and the lower relay drawer wiring.
4. Document the results from the testing and the MPCV-D serial number as well as the nameplate information of the network protector on the maintenance form and the Cascade database.

Test 3 – Relay Tests (continued)

Microprocessor Relays

1. Perform an Overvoltage test and adjust the relay in accordance with the following documents. Record the As-Found and As-Left values.
   - Network Protector Test Set Instructions
   - Relay Instructions
   - Network Protector Instructions
2. Perform a Reverse Current Trip test in accordance with the following documents. Record the As-Found and As-Left values.
   - Network Protector Test Set Instructions
   - Relay Instructions
   - Network Protector Instructions

3. If a Time Delay is used, perform a Time Delay test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions

Test 4 – Ground Fault Test (480V units only)

CAUTION: The ground fault protection circuit between the protector and the customer main service is owned and maintained by the customer. Testing the lock out may call for all protectors to trip. An up-to-date drawing must be made available and reviewed to determine those steps which must be taken to prevent tripping of all protectors.

Verify trip from lockout and block the close of the protectors on all units having a ground fault scheme.

NOTES:

1. The Ground Fault system is typically Customer-owned, and the Lockout is typically Eversource owned. It is important to have an up-to-date print of the scheme prior to performing a test.
2. This test is only to be performed on those units equipped with a ground fault system.

CM-52 Re-install Procedure

1. Inspect the network protector enclosure for chipped, cracked or missing paint, corrosion, etc. Remove any loose paint and/or rust with a wire brush and repaint those areas to prevent further corrosion.
2. Check the condition of the external tank. Check cooling fins to ensure that they are not clogged, missing, or in need of replacement.
3. Check the door gasket to ensure it is still in good condition.
4. Apply gasket preservative to the door gasket.
5. Apply anti-seize grease to the door bolt hardware.
6. Verify that the External Handle is in the OPEN position.
7. Lift the Lever-in drive shutter door and insert the 3/8” square end of the wrench into the Lever-in drive socket.
8. Turn the socket clockwise until the RED indicator appears.
9. Remove the crank and secure it.
10. Close the door.
11. Tighten the hinge bolts.
12. Tighten all door bolts (The tank is secure once the 2 jam (stop) nuts touch the tank.) **NOTE**: The use of impact tools is not recommended and could lead to moving stop nuts for proper sealing and premature door gasket damage.)
13. Verify the protector enclosure is holding pressure using a pressure gauge/fill device. If it is not, perform a **leak check** on those network protectors with submersible enclosures as follows:
    a) Pressurize the enclosure with 5 PSI of dry nitrogen.
    b) Apply a soap solution to the door gaskets, enclosure penetrations, throat gaskets, operating handle gaskets, welds, etc.
    c) Let this sit for 30 minutes.

d) Check for leaks by looking for soap bubbles. Fix any leaks if possible.
e) Record any leaks on the inspection form and alert supervision.
f) Reduce the pressure within the enclosure to 1.5 PSI.

14. Place the operating handle in the as-found position.
15. Record the as-left counter reading.

6.29B - CMD Network Protectors – Major Maintenance

CAUTION

1. No modifications to network protectors shall be made, either temporary or permanent, without prior approval of the Distribution Engineering Department.
2. Stop the job, place equipment in a safe condition, and contact Supervision if the process does not proceed as expected, if unusual situations occur during the performance of the process, or any significant problems occur during maintenance activities.

Before You Begin

Prior to assigning work on network protectors, Supervision shall:

1. The Supervision shall, prior to assigning personnel to perform “Work” on a network protector, ENSURE the person(s) responsible for performing the “Work” is fully qualified in accordance with operating company requirements
2. The Supervision shall, ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
   - TD 211, “When to Wear FR Clothing”
   - TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut, Western MA only)
   - TD 955, “Confined Space Requirements”
   - Eversource Employee Safety Manual
   - TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (CL&P ONLY)
3. The Supervision shall, ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
   - Safety Glasses with side shields
   - EH (Electrical Hazard) rated boots
   - High Voltage gloves
   - FR (flame resistant) clothing, as specified in TD 211
4. Whenever “Work” is performed on a network unit as defined in paragraph 5 of this procedure, the following PPE is required :
   - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or company approved equivalent.
   - Safety glasses with side shields

- Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)
- Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall)

5. All persons performing "Work" on Network Units as defined below and those persons within the immediate work zone while "Work" is being performed shall wear at minimum double layer full body FR clothing, minimum 25 cal. FR rated hood (beehive type with built-in arc rated face shield), safety glasses and, minimum of low voltage (Class 0) rubber gloves (high voltage rubber gloves preferred). As defined in this document, "Work" includes the following tasks:
   - installing or removing transformer links and network fuses
   - rolling or racking out the protector
   - phasing the unit
   - connecting test leads to an energized bus
   - obtaining transformer and network voltages
   - test probe usage prior to installing links and network fuses
   - or any other work performed inside the network protector enclosure with the transformer and/or network bus energized
6. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
   - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to CL&P and WMECO)
   - If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
   - The deficiencies described below, require the primary circuit to be de-energized in accordance with the operating policy.
     - o Major maintenance not performed within the maintenance cycle required by the Eversource Maintenance Program
     - o Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level
     - o Any other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage / corrosion in the network protector or other defect that requires immediate repair to return to service.

7. For cases where multiple network transformers exist in a vault, it will generally not be possible to de-energize all of those units for a variety of reasons. Therefore, prior to working on a network transformer, where multiple network transformers exist in a vault, maintenance records shall be reviewed for major deficiencies and/or major maintenance completion within the maintenance cycle per the Employee maintenance manual prior to working in the vault.
    - If records indicate that major maintenance for all transformers within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
    - If major deficiencies or major maintenance was not completed, management will jointly work with employees for the appropriate steps to follow.
8. With the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro-filling) is being performed.
    - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
9. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.
10. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
11. Supervision shall ensure the assigned workers have primer, paint, and any additional material needed for cleaning and preservation of the exterior of the network protector prior to departing the work center.
12. Prepare the vault for entry.
    a. Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment
    b. Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    c. Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Network Protector Tools

The following fully insulated tools are available and may be useful for Network Protector Service:

Tool Description	NU Stock Code
Wrench, Torque, 1/2” drive	0441650
Wrench, Socket, extension bar, 1/2” drive, 12” long	0441649
Socket size 3/4”, 1/2” drive, 6 pt.	0441652
Socket size 9/16”, 1/2” drive, 6 pt.	0441651
Wrench, Socket, T Handle, 33” long, 9/16” socket	0441646
Wrench, Socket, T Handle, 33” long, 3/4” socket	0441647
Wrench, Socket, T Handle, 33” long, 7/8” socket	0441648
Test Probe	0441607
ETI Relay Programmer	0400188
MPCV Relay Programmer	0445902

The above listed wrenches may be available in other lengths by special order. The insulation from the time of original manufacture has been increased at the request of Eversource and stock code revisions will reflect “FI” for “Fully Insulated”.

NOTE: The orange surface insulation on these tools has a yellow undercoat. If yellow is detected on the surface due to cuts or punctures, the surface insulation has been compromised and the tool should be retired.

Rolling Out the Protector

Reminder: Although it is not shown in some of the following figures, proper PPE must be worn while performing maintenance and testing on all Network Protectors.

NOTE: The CMD Network Protector is a dead-front, racked-in device that does not require the handling of energized links and/or fuses.

The CMD requires the following procedure for its removal from the housing.

1. Prior to operating the network protector handle, vent the protector cabinet as follows:
    a) Loosen the enclosure cover bolts on the side opposite from the operating handle in order to vent the protector.
2. Operate the network protector handle while standing to the side of the enclosure or as far away as possible from the front of the enclosure. Leave the handle in the “**OPEN**” position.
3. Verify that the network protector mechanism is in the open position as follows:
    a) Inspect the network protector position indicator through the network protector enclosure window. Verify the status flag reads **OPEN**.

CAUTION: If the protector contacts do not open, *stop all work* and place the network protector in a safe condition and contact your supervisor.

b) Use a clamp or rope style current transformer (CT) around the conductors of each phase, verify that the current on each phase is zero. (Zero current may indicate that the breaker position is open or the network protector fuses or cable limiters are blown.)
c) Record the secondary voltages.

4. Lift the extension rails into place.
5. Press the trip lever on the breaker and lift the shutter by hand. (The trip lever must remain pressed in to allow the shutter to be raised.)
6. Inspect the CMD network protector and correct any of the following conditions. Protectors must be racked out for all repairs, except as noted below:

NOTE: The following conditions must be made safe before racking out the protector and repaired after the protector is racked out.

- CMD Ratchet Wheel Assembly, Westinghouse Technical Service Bulletin No.930614, Dated June 14, 1993 for units produced after November 1992.(Attachment #1).
- CMD Auxiliary Switch Stop Retrofit Kit, Westinghouse Technical Service Bulletin No 890105 for units produce from January 1987 to August 1987. (Attachment #2).



Figure 1 – The Levering Crank

7. Insert the levering crank (Figure 1) into the Lev-in device and rack the breaker out of the enclosure.
8. Pull the breaker to the edge of the rails (using the handles on the shield) to ensure the anti-tilt pins are under the extension rail keepers. See Figure 2. (This will ensure the breaker does not tilt during maintenance.)

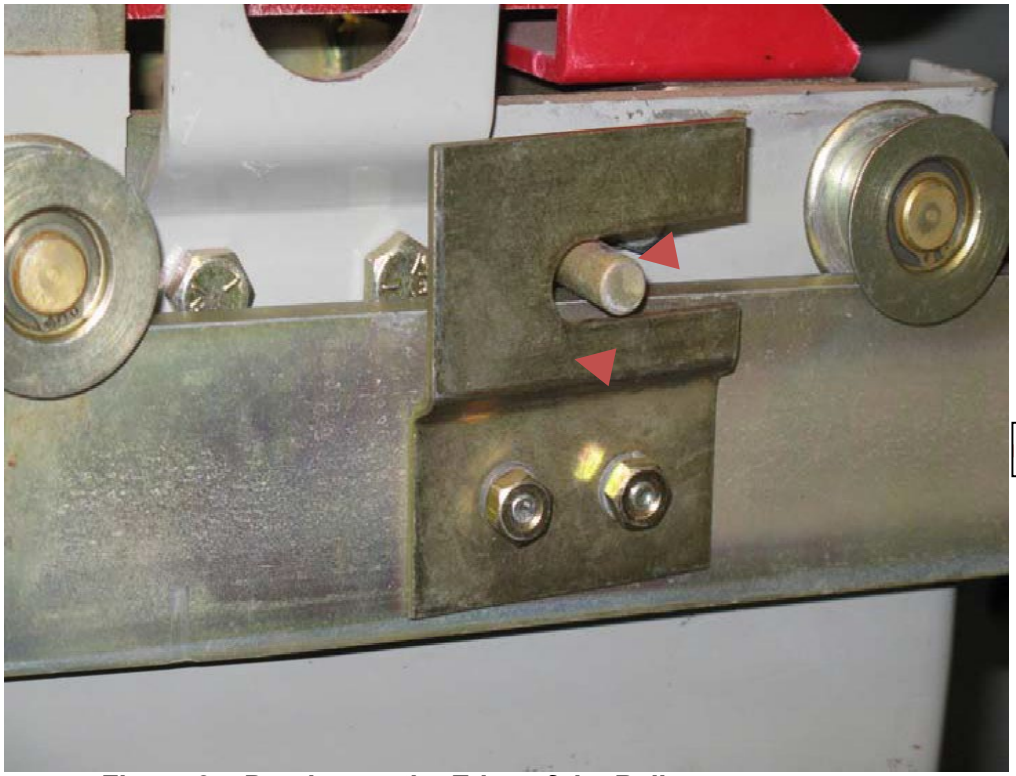


Figure 2 – Breaker on the Edge of the Rails

CAUTION: If a capacitor is present, always press the red button down when performing maintenance in order to prevent electric shock.

9. Press the red button if a capacitor is present. This step does not apply to older models that do not utilize the capacitor.

NOTE: Convert all DTA actuators to CTD at this time. See Section 1 of the Network Protectors Maintenance Manual for details.

10. Turn the three thumbscrews located toward the top of the shield counter-clockwise and lift up so that the shield can be removed.

Breaker Mechanical Inspection:

1. Record the counter reading.
2. Check for broken or damaged barriers on breaker and housing.
3. Check for any signs of liquid entry into enclosure, transformer throat, etc.
4. Check for indication of overheating.
5. Check for loose hardware.
6. Check the arc chutes. Look through them to ensure the vents are free and clear.
7. Manually close the breaker with the charge handle.
8. Install a blocking bar over the trip bar to ensure the breaker is not accidentally tripped. See Figure 3.

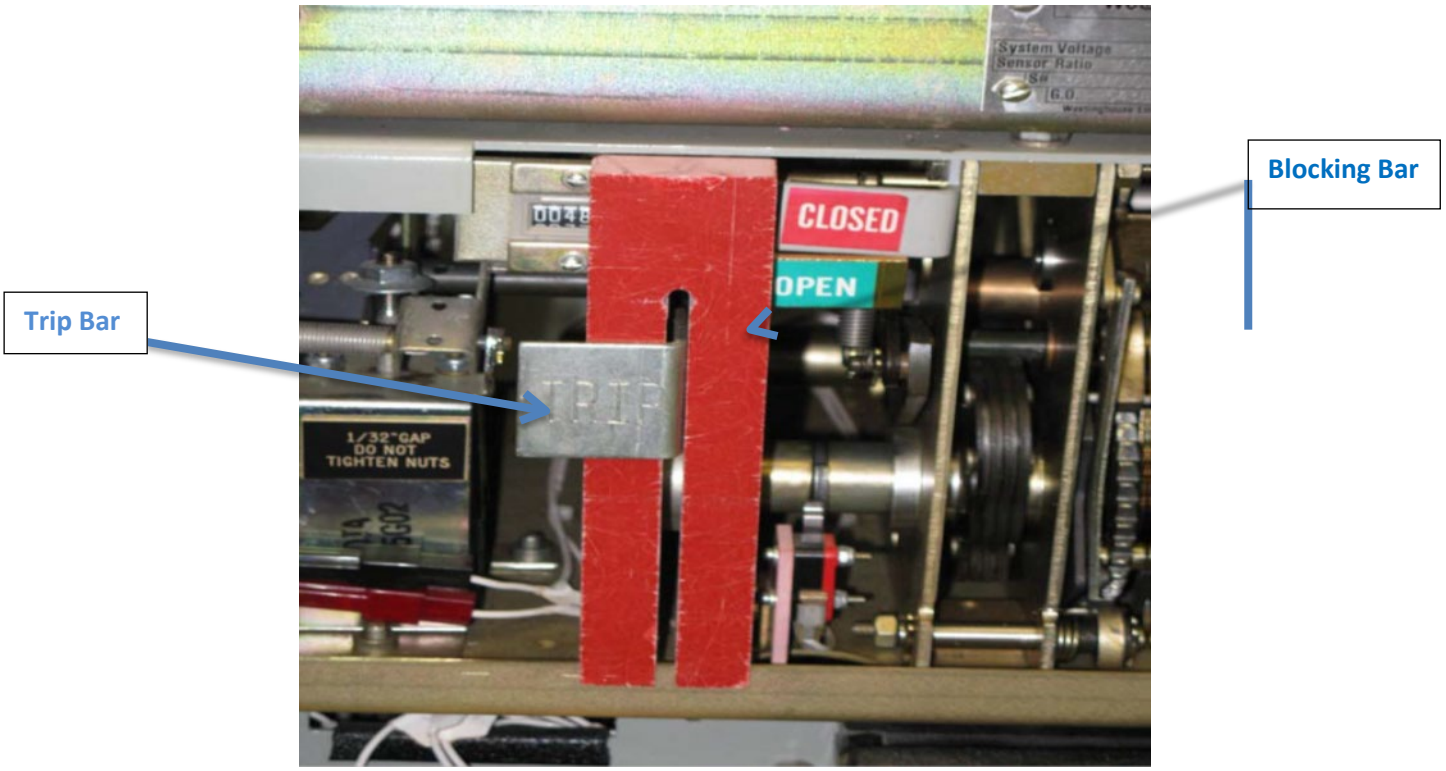


Figure 3 – The Blocking Bar

9. Check the contact pressure using the CMD contact pressure gauge.
NOTE: The procedure varies with the size of the network protector. Use the procedure in the following section that applies to the protector on which you are working.

Checking Contact Pressure on Large Frame (2500 – 3000A) CMD Protectors

1. Ensure that:
   - The Breaker is racked out onto rails.
   - The Capacitor is discharged using the pushbutton.
   - The Front Shield and Arc Chutes removed.
   - The Breaker is in the **closed** position.

CAUTION: The Contact Pressure Gauge is NON-INSULATED.

2. Use the bottom edge of the contact pressure gauge as shown below. The gauge is 0.13 thick and 0.19 wide at the bottom. Use the 0.19 side for checking contact adjustment. See Figure 4.
   - Use the top of the gauge for 1875 Amp protectors.
     Use the handle for 3000 Amp protectors.



Figure 4 – The Contact Pressure Gauge

3. Place the contact gauge between the moving head and the side of the cage assembly. See Figure 5.

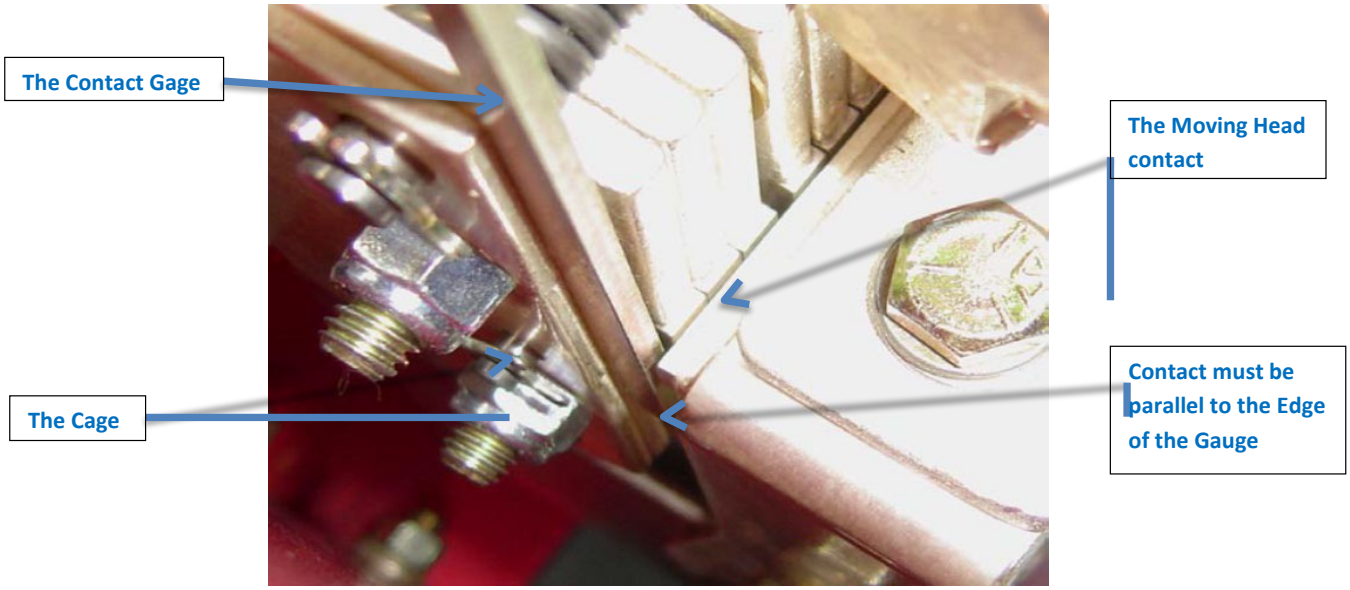


Figure 5 – Checking the Contact Adjustment

4. Use the bottom edge of the gauge to determine if there is a lot of movement between the cage and the moving contact head.
5. Slide the handle side of the gauge to ensure the minimum gap exists. It should fit into the gap without a lot of additional clearance. See Figure 6.
    - If the gap is too small for the handle side of the gauge, adjust the contacts until the gauge will slide into the gap with interference.
6. Adjust the contacts as necessary

NOTE: It is essential that the CMD contact pressure is check and adjusted as necessary to ensure the proper functionality of the protector.

7. Once correct pressure is set, lock down top elastic stop nut using 20 ft/lbs for the large adjusting screw and 15 ft/lbs for the small adjusting screw.
8. Remove the blocking bar.
9. Trip the protector and close it manually to ensure correct pressure is set. Slight adjustment many be needed after closing.)

Checking Contact Pressure on Small Frame (1875A) CMD Protectors

1. Ensure that:
    - The Breaker is racked out onto rails.
    - The Capacitor is discharged using the pushbutton.
    - The Front Shield and Arc Chutes removed.
    - The Breaker is in the **closed** position.
2. Use the top of the contact gauge and a small mirror to view the contact pressure.
    - Gauge Part # **3670A81H03**
    - Contact Mirror # **PROTO2373**
3. Locate the gap created by the cage and the main contacts when the breaker is in the **open** position. See Figure 6.

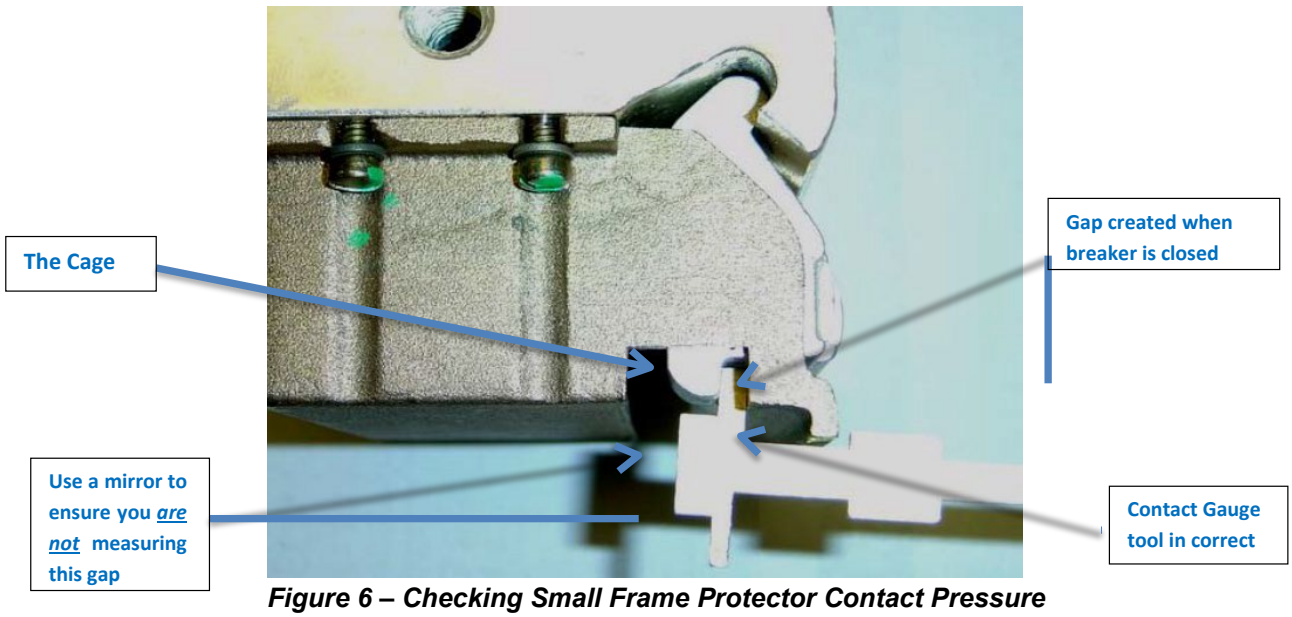


Figure 6 – Checking Small Frame Protector Contact Pressure

4. Slide the **Go** side of the gauge to ensure the minimum gap exists. It should fit into the gap without a lot of additional clearance. See Figure 7.
    - If the gap is too small for the Go gauge, adjust the contacts until the gauge will slide into the gap with interference.
5. Use the **No Go** side of the gauge to ensure the gap is not too large. See Figure 7.
    - If the **No Go** side of the gauge fits into the gap, adjust the contacts to reduce the gap to the point where the **No Go** gauge no longer fits, but the gap is still large enough for the **Go** side of the gauge

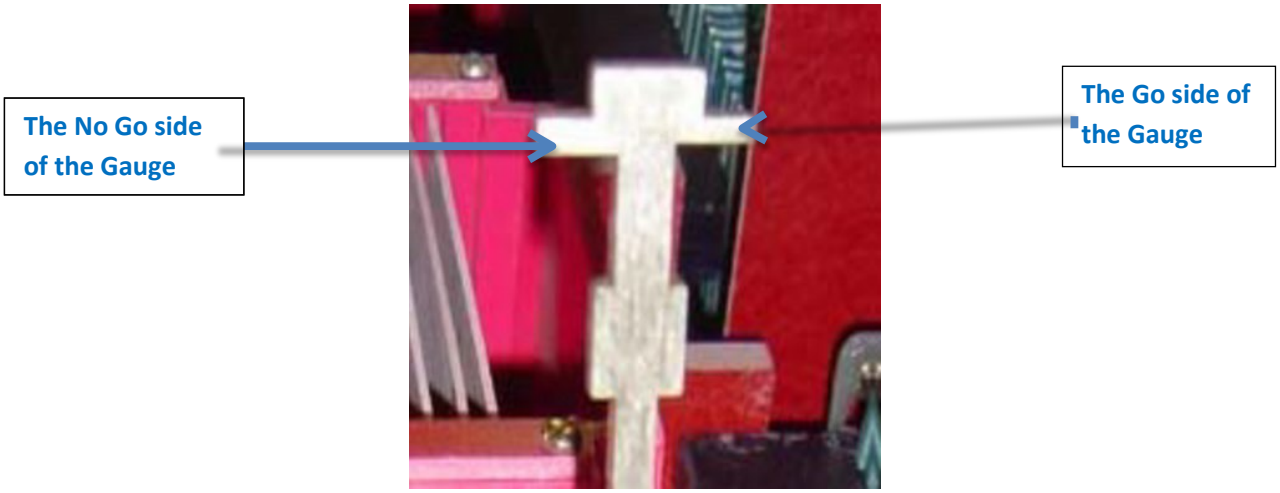


Figure 7 – The Go / No Go Gauge

NOTE: It is essential that the CMD contact pressure is check and adjusted as necessary to ensure the proper functionality of the protector.

6. Once correct pressure is set, lock down top elastic stop nut using 20 ft/lbs for the large adjusting screw and 15 ft/lbs for the small adjusting screw.
7. Remove the blocking bar.
8. Trip the protector and close it manually to ensure correct pressure is set. (Slight adjustment many be needed after closing

Test Sequence:

The following sections are a series of tests defined to ensure proper operation at normal condition and at fault duty. It is important to perform the following tests in *this* order:

1. Manual Operation Test
2. Mechanical Electrical Testing (Voltage Only Testing)
3. Relay Tests
4. Ground Fault Test (480V Unit Only)

Test 1 – Manual Operation Test

1. Exercise the unit at least 5 times – mechanically closing and mechanically tripping the CMD breaker

Test 2 – Mechanical – Electrical Testing (Voltage Only Testing)

Mechanical testing is defined as a “voltage only test” without the use of any network relays (electro-mechanical, solid state or digital). This testing is defined in the IEEE standard for Network Protectors C57.12.44. The basis for this type of testing is the minimum trip and close criteria required.

1. Remove all Network Relays.
    - The phasing relay position type (CNJ) must be jumpered out with the relay removed. (Points 4 &5 on the relay terminal block).
    - A CNJ jumper plate may be required to complete the circuit

CAUTION: Failure to connect the leads in the correct sequence will cause damage to the Network Protector Test Set.

Reminder: Proper PPE must be worn while attaching leads to an energized bus.

2. Connect the Test Set according to the manufacturer’s technical manual and local operating system conditions (phasing).
3. Place a magnet over the Auto button on the JA – JA bracket. See Figure 8

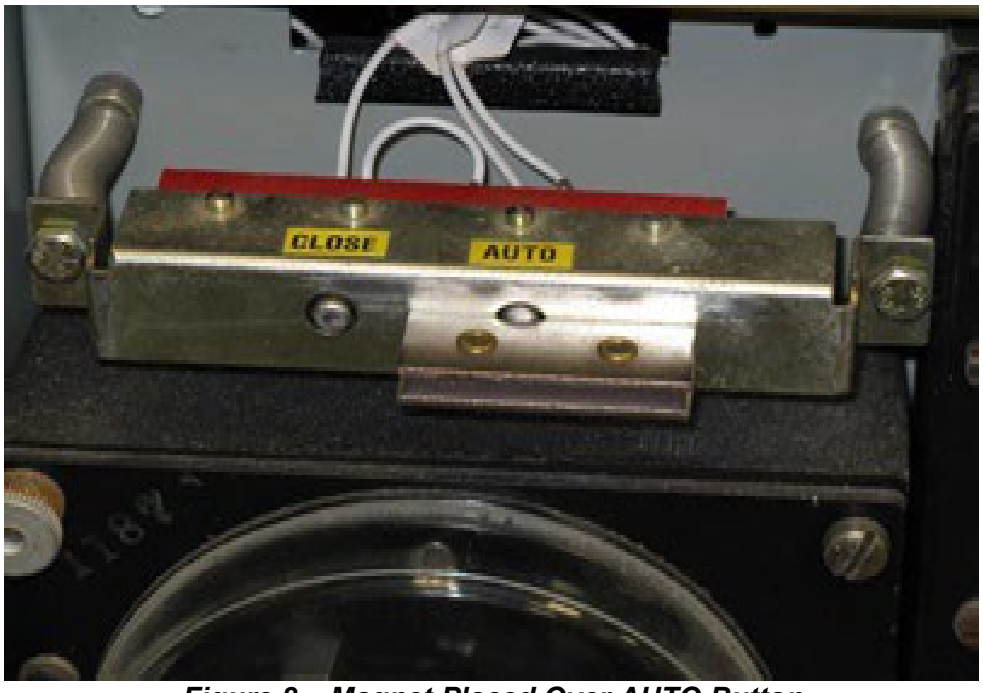


Figure 8 – Magnet Placed Over AUTO Button

NOTE: The schematic will be needed to ensure the proper wires are completed in the closing circuit.

4. Place the Close jumper accordingly on the secondary disconnects or the fuse block to complete the close circuit.
5. Operate the protector at full voltage to ensure everything is operational.

MIN CLOSE TESTING

NOTE: The following procedure takes place after the breaker has been operated at full voltage.

1. Apply 73% of the L-L system voltage. See Table 1. The breaker should NOT close at this level. If the breaker closes, the motor control relay will need adjustment via the adjustable resistor.
2. Apply 80% of the L-L system voltage. See Table 1. The breaker should close.

MIN TRIP TESTING

NOTE: The CMD Protector has two possible testing procedures. Replace all DTA actuators with Capacitive Trip Devices.

Table 1 Test Values

Test	%	125/216V	277/480V
a) Minimum Trip	7.5%	16.2V or Less	36.0V or Less
b) Minimum Motor Close Voltage	73%	158V or Less	350V or Less
c) No Pickup (Motor Relay)	73%	158V or Less	350V or Less
d) Min Pickup (Motor Relay)	80%	160V – 173V	354V – 384V

Mechanical – Electrical Testing - continued

Capacitor Testing

1. Close the protector using full voltage.
2. Turn the test set off. (The set will not be turned back on until this test is completed.)
3. Press the trip button on the test set.
4. Manually charge the protector via the handle.
5. Continue to trip the protector via the push button or jumper a minimum of 3 times. (If the capacitor cannot trip the breaker 3 times, it must be replaced.)

Anti-Close Relay Testing

The CMD is equipped with a BF2 relay that ensures the breaker opens the close circuit and engages the trip circuit.

NOTE: The breaker must be open for this test.

1. Connect the Common & Close leads to the relay terminal block.
2. Connect the Jumper to Common & Trip points on the relay terminal block.
3. Apply rated voltage to the protector. (**NOTE**: BF2 should pick up.)

4. Press the Close button on the test set. The motor should not operate.
5. Manually start to close the mechanism using the handle until the “W” switch changes states. (**NOTE**: The Anti-Close coil must pick up)
    - The Anti-Close assembly should rotate the trip bar on the protector such that the breaker cannot be manually closed.

Test 3 – Relay Tests

Electro-mechanical Relay

1. Perform the Master Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
2. Perform the Phasing Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
3. Perform the Reverse Current Limiting Trip test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
4. If a BN relay is installed, perform the Timing test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
    -

Relay Tests (continued)

Solid State / Microprocessor Relays

1. Perform an Overvoltage test and adjust the relay in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
2. Perform a Reverse Current Trip test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions

- Network Protector Instructions

3. If a Time Delay is used, perform a Time Delay test in accordance with the following documents. Record the As-Found and As-Left values.
   - Network Protector Test Set Instructions
   - Relay Instructions
   - Network Protector Instructions

Test 4 – Ground Fault Test (480V units only)

CAUTION: The ground fault protection circuit between the protector and the customer main service is owned and maintained by the customer. Testing the lock out may call for all protectors to trip. An up-to-date drawing must be made available and reviewed to determine those steps which must be taken to prevent tripping of all protectors.

Verify trip from lockout and block the close of the protectors on all units having a ground fault scheme.

NOTES:

1) The Ground Fault system is typically Customer-owned, and the Lockout is typically Eversource owned. It is important to have an up-to-date print of the scheme prior to performing a test.
2) This test is only to be performed on those units equipped with a ground fault system.

CMD Re-install Procedure

1. Re-install the arc chutes, front and front shield. Check to ensure the unit opens.
2. Roll the unit back into housing to its installed position.
3. With a CMD wrench, rack the protector back into the enclosure.
4. Apply anti-seize grease to door bolt hardware.
5. Apply gasket preservative to door gasket.
6. Tighten all door bolts. The tank is secure once the 2 jam (stop) nuts touch the tank. **Note**: Do not use impact tools as this could lead to moving the stop nuts in place for proper sealing and cause premature door gasket damage.
7. Verify the protector enclosure is holding pressure using a pressure gauge/fill device. If it is not, perform a **leak check** on those network protectors with submersible enclosures as follows:
   a) Pressurize the enclosure with 5 PSI of dry nitrogen.
   b) Apply a soap solution to the door gaskets, enclosure penetrations, throat gaskets, operating handle gaskets, welds, etc.
   c) Let this sit for 30 minutes.
   d) Check for leaks by looking for soap bubbles. Fix any leaks if possible.
   e) Record any leaks on the inspection form and alert supervision.
   f) Reduce the pressure within the enclosure to 1.5 PSI.

8. Place operating handle in as-found condition.
9. Record the “as-left” counter reading

6.29C - MG8/9 Network Protectors – Major Maintenance

CAUTION

1. No modifications to network protectors shall be made, either temporary or permanent, without prior approval of the Distribution Engineering Department.
2. Stop the job, place equipment in a safe condition, and contact Supervision if the process does not proceed as expected, if unusual situations occur during the performance of the process, or any significant problems occur during maintenance activities.

Before You Begin

Prior to assigning work on network protectors, Supervision shall:

1. The Supervision shall, prior to assigning personnel to perform “Work” on a network protector, ENSURE the person(s) responsible for performing the “Work” is fully qualified in accordance with operating company requirements
2. The Supervision shall, ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
    - TD 211, “When to Wear FR Clothing”
    - TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut and Western MA only)
    - TD 955, “Confined Space Requirements”
    - Eversource Employee Safety Manual
    - TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (Connecticut ONLY)
3. The Supervision shall, ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
    - Safety Glasses with side shields
    - EH (Electrical Hazard) rated boots
    - High Voltage gloves
    - FR (flame resistant) clothing, as specified in TD 211
4. Whenever “Work” is performed on a network unit as defined in paragraph 5 of this procedure, the following PPE is required:
    - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or company approved equivalent.
    - Safety glasses with side shields
    - Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)

- Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall)

5. All persons performing “Work” on Network Units as defined below and those persons within the immediate work zone while “Work” is being performed shall wear at minimum double layer full body FR clothing, minimum 25 cal. FR rated hood (beehive type with built-in arc rated face shield), safety glasses and, minimum of low voltage (Class 0) rubber gloves (high voltage rubber gloves preferred). As defined in this document, “Work” includes the following tasks:
   - Installing or removing transformer links and network fuses
   - Rolling or racking out the protector
   - Phasing the unit
   - Connecting test leads to an energized bus
   - Obtaining transformer and network voltages
   - Test probe usage prior to installing links and network fuses
   - Or any other work performed inside the network protector enclosure with the transformer and/or network bus energized
6. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
   - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to Connecticut and Western MA).
   - If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
   - The deficiencies described below, require the primary circuit to be de-energized in accordance with the operating policy.
     - Major maintenance not performed within the maintenance cycle required by the Eversource Maintenance Program
     - Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level
     - Any other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage / corrosion in the network protector or other defect that requires immediate repair to return to service.

7. For cases where multiple network transformers exist in a vault, it will generally not be possible to de-energize all of those units for a variety of reasons. Therefore, prior to working on a network transformer, where multiple network transformers exist in a vault, maintenance records shall be reviewed for major deficiencies and/or major maintenance completion within the maintenance cycle per the Eversource Maintenance Program prior to working in the vault.
    - If records indicate that major maintenance for all transformers within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
    - If major deficiencies or major maintenance was not completed, management will jointly work with employees for the appropriate steps to follow.
8. With the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro-filling) is being performed.
    - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
9. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.
10. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
11. Supervision shall ensure the assigned workers have primer, paint, and any additional material needed for cleaning and preservation of the exterior of the network protector prior to departing the work center.
12. Prepare the vault for entry.
    a. Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment
    b. Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    c. Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Network Protector Tools

The following fully insulated tools are available and may be useful for Network Protector Service:

Tool Description	NU Stock Code
Wrench, Torque, 1/2” drive	0441650
Wrench, Socket, extension bar, 1/2” drive, 12” long	0441649
Socket size 3/4”, 1/2” drive, 6 pt.	0441652
Socket size 9/16”, 1/2” drive, 6 pt.	0441651
Wrench, Socket, T Handle, 33” long, 9/16” socket	0441646
Wrench, Socket, T Handle, 33” long, 3/4” socket	0441647
Wrench, Socket, T Handle, 33” long, 7/8” socket	0441648
Test Probe	0441607
ETI Relay Programmer	0400188
MPCV Relay Programmer	0445902

The above listed wrenches may be available in other lengths by special order. The insulation from the time of original manufacture has been increased at the request of Eversource and stock code revisions will reflect “FI” for “Fully Insulated”.

NOTE: The orange surface insulation on these tools has a yellow undercoat. If yellow is detected on the surface due to cuts or punctures, the surface insulation has been compromised and the tool should be retired.

Rolling Out and Isolating the Protector

Reminder: Although it is not shown in some of the following figures, proper PPE must be worn while performing maintenance and testing on all Network Protectors.

NOTE: The MG8/9 Network Protectors are live-front, bolted-in-place devices requiring the handling of energized links and/or fuses. Because of this, it is imperative that they be out on the rails and isolated from the energized bus work of the enclosure before any work or testing is done.

The MG8/9 requires the following procedure for its removal from the housing.

1. Prior to operating the network protector handle, vent the protector cabinet as follows:
    a) Loosen the enclosure cover bolts on the side opposite from the operating handle in order to vent the protector.
2. Operate the network protector handle while standing to the side of the enclosure or as far away as possible from the front of the enclosure. Leave the handle in the “open” position.
3. Verify that the network protector mechanism is in the open position as follows:

a) Inspect the network protector position indicator through the network protector enclosure window to ensure the Positive indicator reads OPEN.
b) Use a clamp or rope style current transformer (CT) around the conductors of each phase, verify that the current on each phase is zero. (Zero current may indicate that the breaker position is open or the network protector fuses or cable limiters are blown.)
c) Record the secondary voltages.

CAUTION: If the protector contacts do not open, *stop all work* and place the network protector in a safe condition and contact your supervisor.

4. Ensure that there are adequate clearances between energized parts and the ground and that the top housing and bottom barriers are in place.
   - Install temporary boards as necessary to provide adequate Clearances.

CAUTION: The following steps require the use of a Company-approved insulated wrench and that you use wear the appropriate PPE.

5. For top-connected protectors:
   - Remove the fuses without disturbing the fuse connecting blocks. See Figure 1.
   - Remove the fuse connecting blocks and the screws securing the protector unit to the low voltage transformer bushing. See Figure 1.

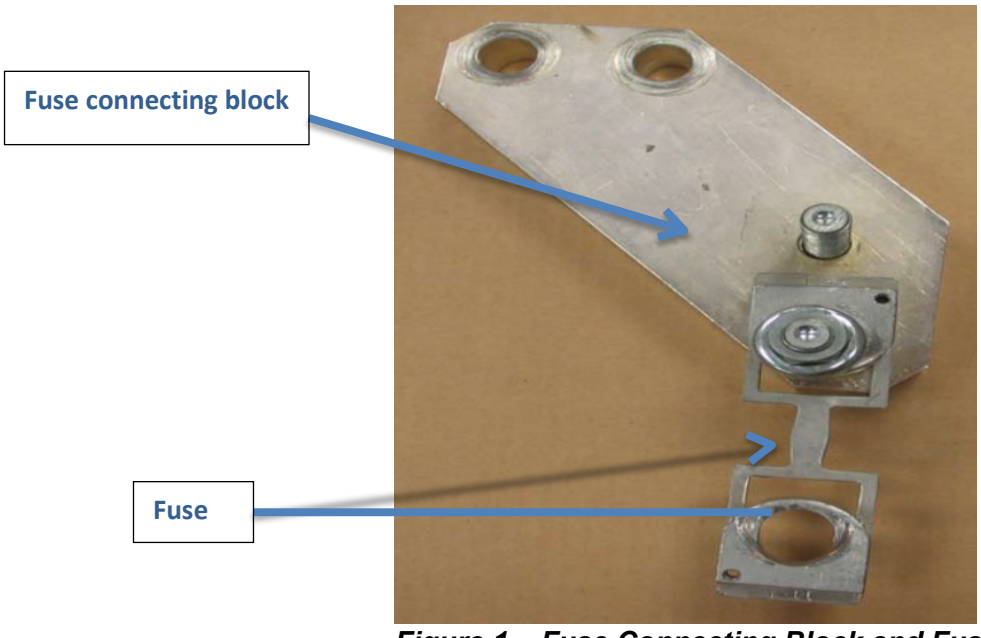


Figure 1 – Fuse Connecting Block and Fuse

For protectors above 1875 amperes:

- Remove the fuses at the top of the protector.
- Remove the disconnect links at the bottom of the protector unit.

CAUTION: On Network Protectors with the transformer bus on the bottom, remove the transformer links first to allow the removal of the fuse nuts.

6. Store all fuses, fuse nuts, and links on the inside door ledge of the Network Protector.
7. Loosen the 4 bolts that fasten the rollout unit to the housing.
8. Install the rail extensions, ensuring they are locked in place, and move the rollout unit from the housing.

Breaker Mechanical Inspection:

1. Record the counter reading.
2. Check for broken or damaged barriers on breaker and housing.
3. Check for any signs of liquid entry into enclosure, transformer throat, etc.
4. Check for indication of overheating, including discoloration of the bus or barrier boards or greenish brown paraffin like substance in the bottom of the enclosure and area as this may indicate degradation of insulation backboards.
5. Use a drop of oil on all mechanism pins.
6. Inspect and clean the motor housing race.
    a) Inspect the motor and brushes for wear.
    b) Check the torque brake for absence of grease or oil and for wear on the drum and shoe surfaces.
    c) Check the gear reducer oil level.
7. Inspect for loose wiring at control components:
    - Motor control relay
    - Resistors
    - Terminals
    - Auxiliary switches
8. Check for frayed, cracked, or damaged control wire. Asbestos coated wiring or older wire harness may require an additional dielectric test to determine if it has reached its useful life. See Dielectric Testing.
9. Check for loose hardware.
10. Check the door gasket to ensure it is in good condition.
11. Fuse Inspection: (See Figure 2.)
    a) For the Y and Z fuses:
        - Examine the fuse element to ensure that no visible cracks are present in the element and there are no signs of slow melt.
    b) For the alloy fuses:
        - Examine the fuse element to ensure that no visible cracks are present in the element and there are no signs of slow melt.
        - Place the fuse flat on the top surface of the housing door.

- Ensure that the fuses rock. Discard any alloy fuses that are annealed flat, thus eliminating the required spring action.

NOTE: 480Y/277 Voltage units alloy fuses (shown on left) require the extended arc horn and addition barrier to properly clear the phase. Fuses are embossed with the style number that correlates to ampere and curve characteristics.

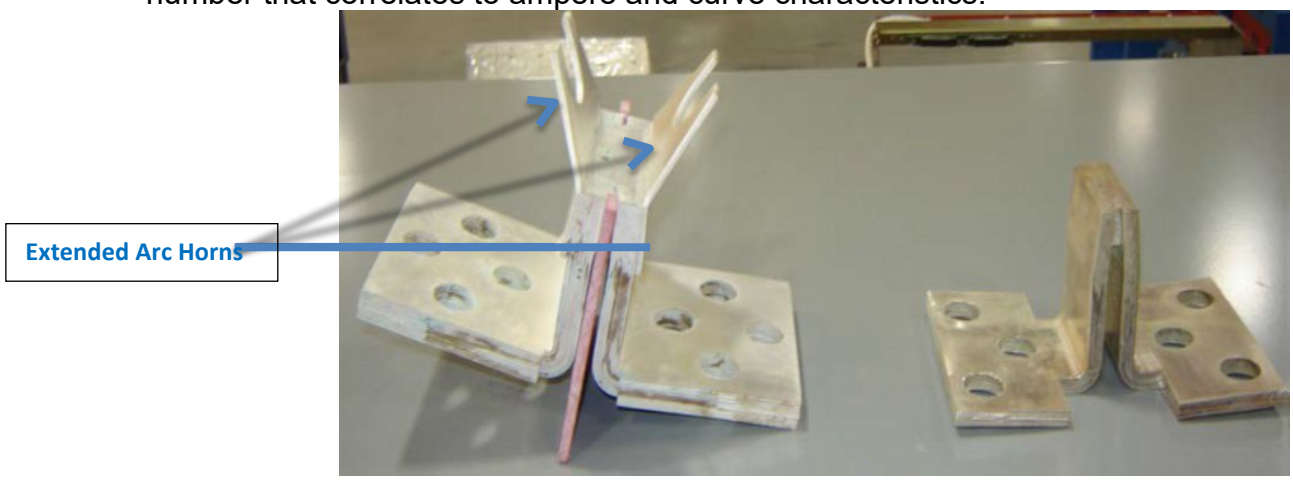


Figure 2 – Fuses

12. Remove and inspect the arc chutes and contacts.

> **CAUTION**: Some arc chutes are made from asbestos. Use hazardous material handling procedures for these and *do not* clean them. Replace them instead.

- Arc chutes must be free and clear of any carbon buildup. Clean as necessary.
- Inspect contacts for excessive pitting and dress the contacts as necessary.

13. Check the cross bar insulation and ensure that no buildup is on the backboard between the phases.
14. Check for melted paraffin in the bottom of the enclosure which indicates possible deterioration of the backer board.

Testing Sequence:

The next section is a series of tests defined to ensure proper operation at normal condition and at fault duty. It is important to perform the following tests in *this* order:

Test 1 Manual Breaker Operation Test

Test 2 Insulation Resistance Testing (Megger)

Test 3 Micro-Ohm Test (Ductor)

Test 4 Mechanical Electrical Test (Voltage Only Testing)

Test 5 Relay Tests

Test 6 Ground Fault Test (480V Unit Only)

Test 1 – Manual Breaker Test

1. Operate the breaker manually while it is on rails using an external closing prop on the handle. Close and trip the breaker 5 times to verify proper mechanical operation. At least one of these operations should be performed with the protector in the enclosure with the fuses removed.

Test 2 – Insulation Resistance Test (Megger)

The GE MG8/9 breaker is constructed upon a common insulated back board and requires periodic insulation integrity checks to ensure proper isolation. In addition, the breaker construction relies upon an insulated cross bar on the breaker. This ties all 3 phases together and must be periodically checked to ensure compliance.

1. Remove all potential leads from the breaker bus.
2. Remove A, B, and C Links to isolate the resistance circuit.
3. Using at least a 1,000 VDC Megger, complete the 9-point test outlined in the chart below: An acceptable value is 10 Meg Ohms or greater for a 1 minute time duration.

Backboard Insulation			
Breaker Position OPEN			
Reading Location	N1 to T1	N2 to T2	N3 to T3
Inspection Value			
Crossbar Insulation			
Breaker Position CLOSED			
Reading Location	N1 to GND	N2 to GND	N3 to GND
Inspection Value			
Crossbar Insulation			
Breaker Position CLOSED			
Reading Location	N1 to N2	N2 to N3	N3 to N1
Inspection Value			

Test 3 – Micro-Ohm Test (Ductor)

Perform an as-found and then after cleaning, a final ductor test. The maximum acceptable value for ductor testing is 25 micro-ohms or less, using a 100 Amp ductor.

1. With the breaker closed, connect the micro-ohm test leads to the network protector.
2. Test and record the value.
    - If the contact resistance (micro-ohm reading) is greater than 25 micro-ohms:
        - ❖ Open the breaker and clean the contact surface with Scotch Brite.
        - ❖ Re-test and record the "as-left" value.
        - ❖

Test 4 – Mechanical – Electrical Test (Voltage Only Testing)

Mechanical testing is defined as a "voltage only test" without the use of any network relays (electro-mechanical, solid state or digital). This testing is defined in the IEEE standard for Network Protectors C57.12.44. The basis for this type of testing is the minimum trip and close criteria required.

1. Remove all Network Relays.
    - The phasing relay Terminal Points 1 & 2 (wires No. 6-6A) must be jumped.
2. Connect the Test Set according to the manufacturer's instruction manual and local system operating conditions (phasing).

CAUTION! - Failure to connect the leads in the correct sequence will cause damage to the Network Protector Test Set.

Reminder: Proper PPE must be worn while attaching leads to an energized bus.

MIN CLOSE TESTING

1. Apply full system voltage to ensure closing operation when the CLOSE button is pressed on the TEST SET.
2. Trip the breaker with the trip lever.
3. Apply 73% of the L-L system voltage. See Table 1. The breaker should NOT close at this level. If the breaker closes, the motor control relay will need adjustment. The Motor Control Relay is located below the mechanism. To make adjustments:
    a) Remove the steel guard.
    b) Use 3/8" wrenches to hold the bottom fixed nut and adjust the upper nut.
        - **Compress** the spring for a higher value.
        - **Lengthen** the spring for a lower value.

4. Apply 80% of the L-L system voltage. See Table 1. The breaker should close.

Table 1 Test Values

Test	%	125/216V	277/480V
a) Minimum Trip	7.5%	16.2V or Less	36.0V or Less
b) Minimum Motor Close Voltage	73%	158V or Less	350V or Less
c) No Pickup (Motor Relay)	73%	158V or Less	350V or Less
d) Min Pickup (Motor Relay)	80%	160V – 173V	354V – 384V

Mechanical – Electrical Test (continued)

MIN TRIP TESTING

1. With the breaker closed, apply 7.5% of system voltage. See Table 1.
2. Press the TRIP button on the test set.
    - If the protector does not trip at this level, then a sensitivity adjustment is needed on the shunt trip level assembly. The shunt trip assembly and adjustment screw are located on the upper left side of the mechanism.

NOTE: To initially set this device, perform the following:

a) Manually close the breaker.
b) Adjust this screw upward until the breaker opens.
c) Turn the screw back down 1 turn after the opening.
d) Tighten the lock nut.
e) Re-test the min level to determine if this adjustment fits the trip range.

TRIP FREE TEST

NOTE: During Trip Free operation, verify that the main contacts do not close.

Perform the following at full system voltage.

1. With the breaker open, hold the trip latch and hold the “close” button on the protector test set.
2. After two or three operations, release the trip latch. The protector should close on the next close operation.

Test 5 – Relay Tests

Electro-Mechanical Relay Tests

1. Perform the Master Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions

2. Perform the Phasing Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
3. Perform the Reverse Current Limiting Trip test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
4. If a BN relay is installed, perform the Timing test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions

Test 5 - Relay Tests (continued)

Solid State / Microprocessor Relays

1. Perform an Overvoltage test and adjust the relay in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
2. Perform a Reverse Current Trip test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
3. If a Time Delay is used, perform a Time Delay test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions

Test 6 – Ground Fault Test (480V units only)

The ground fault protection circuit between the protector and the customer main service is owned and maintained by the customer. Testing the lock out may call for all protectors to trip. An up-to-date drawing must be made available and reviewed to determine those steps which must be taken to prevent tripping of all protectors.

Verify trip from lockout and block the close of the protectors on all units having a ground fault scheme.
NOTES:

1) The Ground Fault system is typically Customer-owned, and the Lockout is typically Eversource Owned. It is important to have an up-to-date print of the scheme prior to performing a test.
2) This test is only to be performed on those units equipped with a ground fault system.

GE MG8/9 Re-install Procedure

Reminder: Proper PPE must be worn while performing the following steps.

CAUTION: A misaligned operating handle can result in the network protector mechanisms remaining in the "Automatic" position with the network protector operating handle in the "Open" position.

1. Check the operating handle alignment before rolling the protector back into its housing. Ensure the base of the handle is aligned with the slot into which it will fit. See Figure 3.

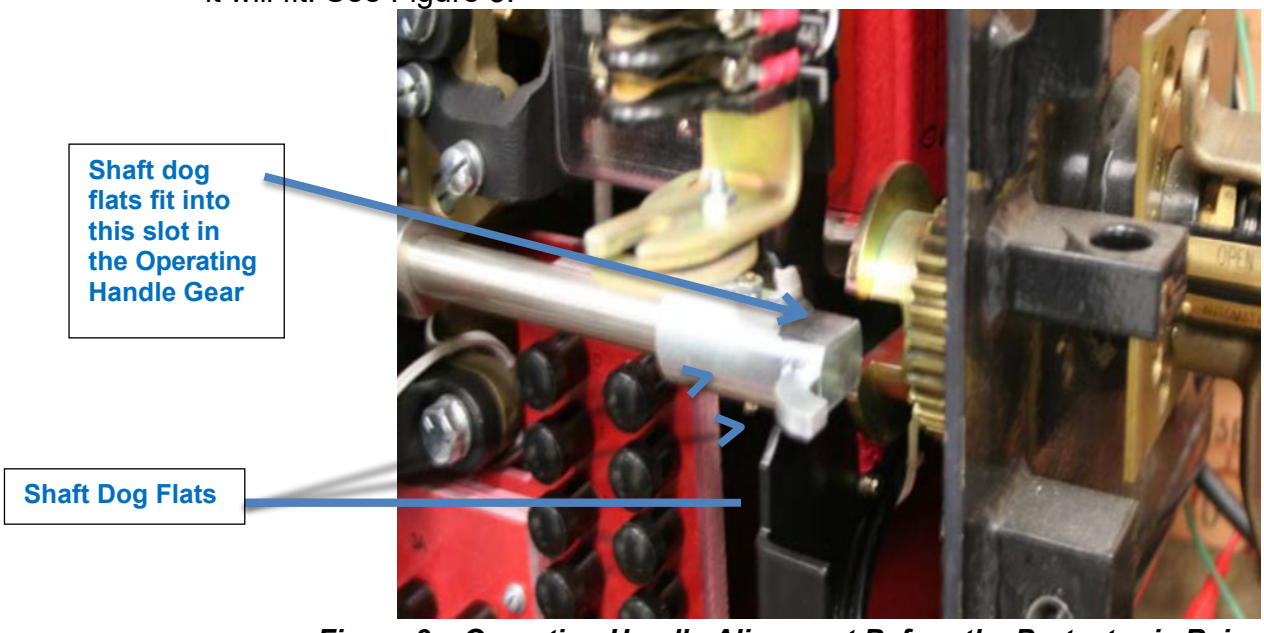


Figure 3 – Operating Handle Alignment Before the Protector is Reinstalled

2. Roll the unit back into the housing to its installed position. Proper alignment of the shaft dog is assured when the two flat surfaces of the shaft dog are fully engaged in the slot on the enclosure's geared operating handle. See Figure 4.

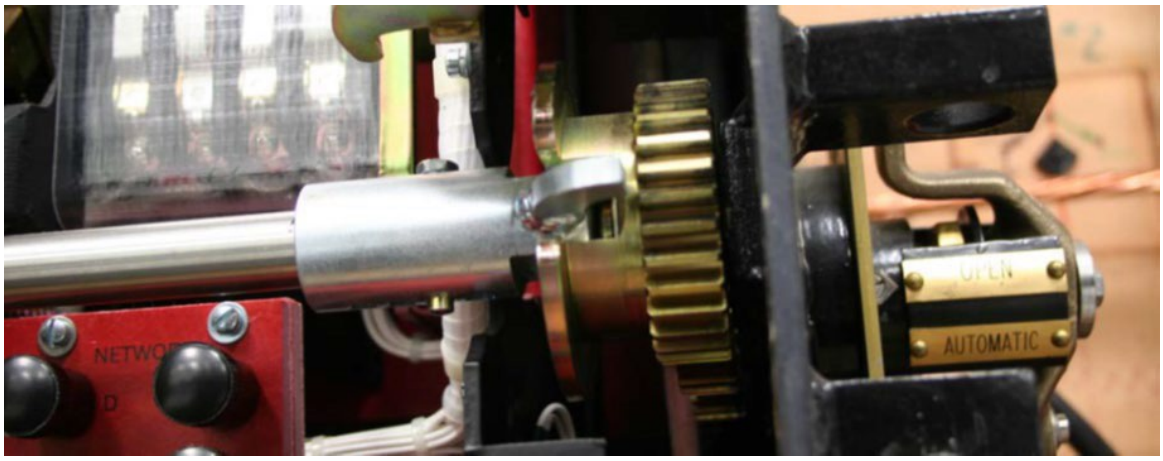


Figure 4 – Operating Handle Properly Aligned

3. With an insulated wrench, tighten the 4 mounting bolts.
4. Using test probes, verify that no shorts exists as follows:
    - For the “I Frame” style, place one insulated test probe at the breaker fuse mounting position for Phase A and the other probe on the network terminal fuse mounting position for Phase A with the protector breaker in the open position. See Figure 4.
    - For the “U Frame” style, the transformer bus touches the transformer shunts as the protector is rolled in, thus eliminating the safety probe on the transformer side.

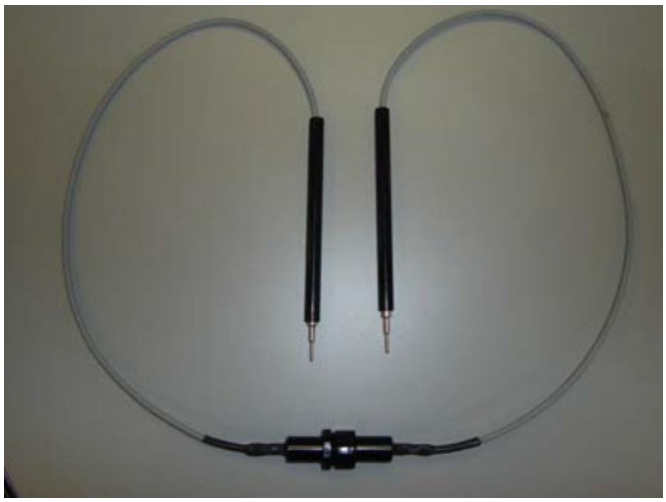


Figure 4 – Insulated Test Probe

5. Check the test fuse continuity across the test probes using a light tester, bell tester, or ohmmeter.
    - If the test fuse has not blown, install the Phase A network fuse using an insulated wrench and wearing the appropriate PPE.
    - If the test fuse has blown, roll the unit back out and check the protector

- and relays for phase-to-ground fault.

6. Repeat the previous step for testing the additional network phases and for testing the transformer side of the protector at the disconnect link mounting locations.
7. Apply anti-seize grease to the door bolt hardware.
8. Apply gasket preservative to the door gasket.
9. Tighten all door bolts. **NOTE:** Use of impact tools is not recommended and could lead to moving stop nuts for proper sealing and premature door gasket damage.
10. Verify the protector enclosure is holding pressure using a pressure gauge/fill device. If it is not, perform a **leak check** on those network protectors with submersible enclosures as follows:
    a) Pressurize the enclosure with 5 PSI of dry nitrogen.
    b) Apply a soap solution to the door gaskets, enclosure penetrations, throat gaskets, operating handle gaskets, welds, etc.
    c) Let this sit for 30 minutes.
    d) Check for leaks by looking for soap bubbles. Fix any leaks if possible.
    e) Record any leaks on the inspection form and alert supervision.
    f) Reduce the pressure within the enclosure to 1.5 PSI.
11. Place the operating handle in as-found position.
12. Record the as-left counter reading.

6.29D - CM-22 Network Protectors – Major Maintenance

CAUTION

1. No modifications to network protectors shall be made, either temporary or permanent, without prior approval of the Distribution Engineering Department.

2. Stop the job, place equipment in a safe condition, and contact Supervision if the process does not proceed as expected, if unusual situations occur during the performance of the process, or any significant problems occur during maintenance activities.

Before You Begin

Prior to assigning work on network protectors, Supervision shall:

1. The Supervision shall, prior to assigning personnel to perform “Work” on a network protector, ENSURE the person(s) responsible for performing the “Work” is fully qualified in accordance with operating company requirements
2. The Supervision shall, ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
    - TD 211, “When to Wear FR Clothing”

- TD 952, “Protection of Personnel Entering Enclosed Spaces” (Connecticut and Western MA only)
- TD 955, “Confined Space Requirements”
- NU System Employee Safety & Health Handbook
- TD -877 Managing Arch Flash Hazards on CL&P Distribution Facilities (Connecticut ONLY)

3. The Supervision shall, ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
   - Safety Glasses with side shields
   - EH (Electrical Hazard) rated boots
   - High Voltage gloves
   - FR (flame resistant) clothing, as specified in TD 211
4. Whenever “Work” is performed on a network unit as defined in paragraph 5 of this procedure, the following PPE is required:
   - Protective Arc Flash Hood (Beehive), (Stock Code 442151) or company approved equivalent.
   - Safety glasses with side shields
   - Minimum of low voltage (Class 0) rubber gloves (use of High Voltage Rubber Gloves is preferred)
   - Double layer of full body FR Clothing (i.e., FR shirt and pants plus full body FR coverall)
5. All persons performing “Work” on Network Units as defined below and those persons within the immediate work zone while “Work” is being performed shall wear at minimum double layer full body FR clothing, minimum 25 cal. FR rated hood (beehive type with built-in arc rated face shield), safety glasses and, minimum of low voltage (Class 0) rubber gloves (high voltage rubber gloves preferred). As defined in this document, “Work” includes the following tasks:
   - Installing or removing transformer links and network fuses
   - Rolling or racking out the protector
   - Phasing the unit
   - Connecting test leads to an energized bus
   - Obtaining transformer and network voltages
   - Test probe usage prior to installing links and network fuses
   - Or any other work performed inside the network protector enclosure with the transformer and/or network bus energized
6. Prior to accessing manholes and vaults to investigate, inspect or work on a network unit in a single transformer vault, the maintenance records for that unit will be reviewed for condition of the unit.
   - If the records indicate that a major maintenance was completed within the maintenance cycle per the Eversource Maintenance Program and the unit has no major deficiencies, work may commence on the network transformer with the unit energized following all applicable company procedures and the protocols. (Applicable only to Connecticut and Western MA)

- If the records do not indicate that a major maintenance was completed on the unit within the maintenance cycle per the Eversource Maintenance Program or major deficiencies have not been addressed, then the primary feed to the unit will be de-energized prior to commencement of maintenance work. The maintenance work on the unit will then take place with the unit de-energized, and only the secondary cables will be energized back from the street grid during the work. This will only apply to single transformer vault units.
- The deficiencies described below, require the primary circuit to be de-energized in accordance with the operating policy.
  - Major maintenance not performed within the maintenance cycle required by the Eversource Maintenance Program.
  - Low oil level (below sight glass / gauge level) in primary switch or transformer or dielectric quality of oil below acceptable level.
  - Any other significant defect or abnormal condition that may affect the safe operation of the network protector or transformer, such as, free standing water in the primary switching or transformer oil sample, excessive damage/ corrosion in the network protector or other defect that requires immediate repair to return to service.

7. For cases where multiple network transformers exist in a vault, it will generally not be possible to de-energize all of those units for a variety of reasons. Therefore, prior to working on a network transformer, where multiple network transformers exist in a vault, maintenance records shall be reviewed for major deficiencies and/or major maintenance completion within the maintenance cycle per the Eversource Maintenance Program prior to working in the vault.
   - If records indicate that major maintenance for all transformers within the vault is up-to-date, and that there are no major deficiencies, then work may proceed.
   - If major deficiencies or major maintenance was not completed, management will jointly work with employees for the appropriate steps to follow.
8. With the exception of the commissioning of a new network unit, 480V/277V network units shall have major maintenance completed with the primary de-energized. 216V/125V network units may be worked on with the primary energized as long as no oil work (i.e. oil sampling, topping off and/or retro- filling) is being performed.
   - Network major maintenance that includes any oil work (i.e. primary equipment oil sampling, topping off or the like) shall only be completed with the primary equipment de-energized
9. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.

10. Review the manufacturer's manuals for all safety notations (Danger, Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.
11. Supervision shall ensure the assigned workers have primer, paint, and any additional material needed for cleaning and preservation of the exterior of the network protector prior to departing the work center.
12. Prepare the vault for entry.
    a. Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment
    b. Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    c. Remove any standing water or debris from the vault in accordance with ENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Network Protector Tools

The following fully insulated tools are available and may be useful for Network Protector Service:

Tool Description	NU Stock Code
Wrench, Torque, 1/2" drive	0441650
Wrench, Socket, extension bar, 1/2" drive, 12" long	0441649
Socket size 3/4", 1/2" drive, 6 pt.	0441652
Socket size 9/16", 1/2" drive, 6 pt.	0441651
Wrench, Socket, T Handle, 33" long, 9/16" socket	0441646
Wrench, Socket, T Handle, 33" long, 3/4" socket	0441647
Wrench, Socket, T Handle, 33" long, 7/8" socket	0441648
Test Probe	0441607
ETI Relay Programmer	0400188
MPCV Relay Programmer	0445902

The above listed wrenches may be available in other lengths by special order. The insulation from the time of original manufacture has been increased at the request of Eversource and stock code revisions will reflect "FI" for "Fully Insulated".

NOTE: The orange surface insulation on these tools has a yellow undercoat. If yellow is detected on the surface due to cuts or punctures, the surface insulation has been compromised and the tool should be retired.

Rolling Out and Isolating the Protector

Reminder: Although it is not shown in some of the following figures, proper PPE must be worn while performing maintenance and testing on all Network Protectors.

NOTE: The CM-22 Network Protector is a live-front, bolted-in-place device requiring the handling of energized links and/or fuses. Because of this, it is imperative that the CM-22 be out on the rails and isolated from the energized bus work of the enclosure before any work or testing is done. The CM-22 requires the following procedure for its removal from the housing.

WARNING: CM-22 Aluminum Bus Issue

WARNING

Small frame (2000 amp and below), submersible Westinghouse, type CM-22 network protectors, containing an aluminum transformer bus may develop a volatile atmosphere within the enclosure if the aluminum transformer bus is exposed to moisture. Network Protectors with the following Shop Order numbers (S.O. #) are suspected to contain Al transformer bus and require the venting prior to operating the handle. This requirement also includes protectors that are found in the open position. In addition, if the nameplate on the network protector is missing or not legible, the network protector shall be treated as if it contains Al bus unless it has been positively identified as containing copper bus.

S.O. #'s Year of Manufacture - 1950-1963



30Y, 31Y, 32Y, 33Y, 35Y, 43Y and 44Y, all followed by four digits (Serial numbers starting with the above but followed by three digits are not affected)

13. Prior to operating the network protector handle, determine if the network protector may contain an aluminum bus, as described in the above **WARNING**. If the protector serial number is within the range of those protectors with aluminum busses, vent the protector cabinet as follows:
    a) Loosen the enclosure cover bolts on the side opposite from the operating handle, while allowing the bolts to remain engaged. Allow for a gap of 1/8" to ¼".
    b) Wait for a minimum of two minutes to allow the enclosure to vent.
    c) Retighten all of the enclosure cover bolts.

14. Operate the network protector handle while standing to the side of the enclosure or as far away as possible from the front of the enclosure. Leave the handle in the "open" position.
15. Verify that the network protector mechanism is in the open position as follows:
    a) Inspect the network protector position indicator through the network protector enclosure window.
    b) Use a clamp or rope style circuit tester (CT) around the conductors of each phase, measure and record the current on each phase of the network protector secondary cables. (Zero current indicates that the breaker position is open.)
    c) Open the enclosure door to inspect the right-hand contacts to verify the contacts are open.

CAUTION: If the protector contacts do not open, *stop all work* and place the network protector in a safe condition and contact your supervisor.

16. Check the protector enclosure and transformer throat area for signs of liquids.
17. Ensure that there are adequate clearances between energized parts and the ground or that adequate barriers exist.
    - Install temporary boards as necessary to provide adequate clearances.
18. Inspect the CM-22 network protector and correct any of the following conditions. Protectors must be racked out for all repairs, except as noted below:

NOTE: The following conditions must be made safe before racking out the protector and repaired after the protector is racked out.

- CM-22 Right Hand Extension Rail Assembly, Westinghouse Bulletin Dated June 16, 1987. (Attachment #1). The rail assembly should be changed before racking out.
- CM-22 Auxiliary Switch Assembly, Westinghouse Technical Service Bulletin No 920519. Replacement required if black-filled polycarbonate is cracked or damaged. (Attachment #2).
- Old Style CM-22 BN Plate replacement. BN Plates manufactured from brown or black phenolic material shall be replaced with BN plates manufactured of Glass Polyester material (Red material).

19. Remove the disconnect links at the bottom of the rollout unit, using an insulated wrench and wearing appropriate PPE.
20. Remove the fuse, using a Company-approved insulated socket wrench in good condition and wearing appropriate PPE.
21. Store all fuses, fuse nuts, and links on the inside door ledge of the Network Protector.
22. Loosen the bolts that fasten the rollout unit to the housing.
    a) Loosen the left hand relay panel bolt and the center mechanism "red" bolt to access the (2) left side bolts.
    b) Disconnect the ground bolt last. See Figure 1.

23. Once all panel mounting bolts are disengaged, swing the relay panel closed and retighten the mechanism red bolt and the relay panel left-hand hold down bolts.

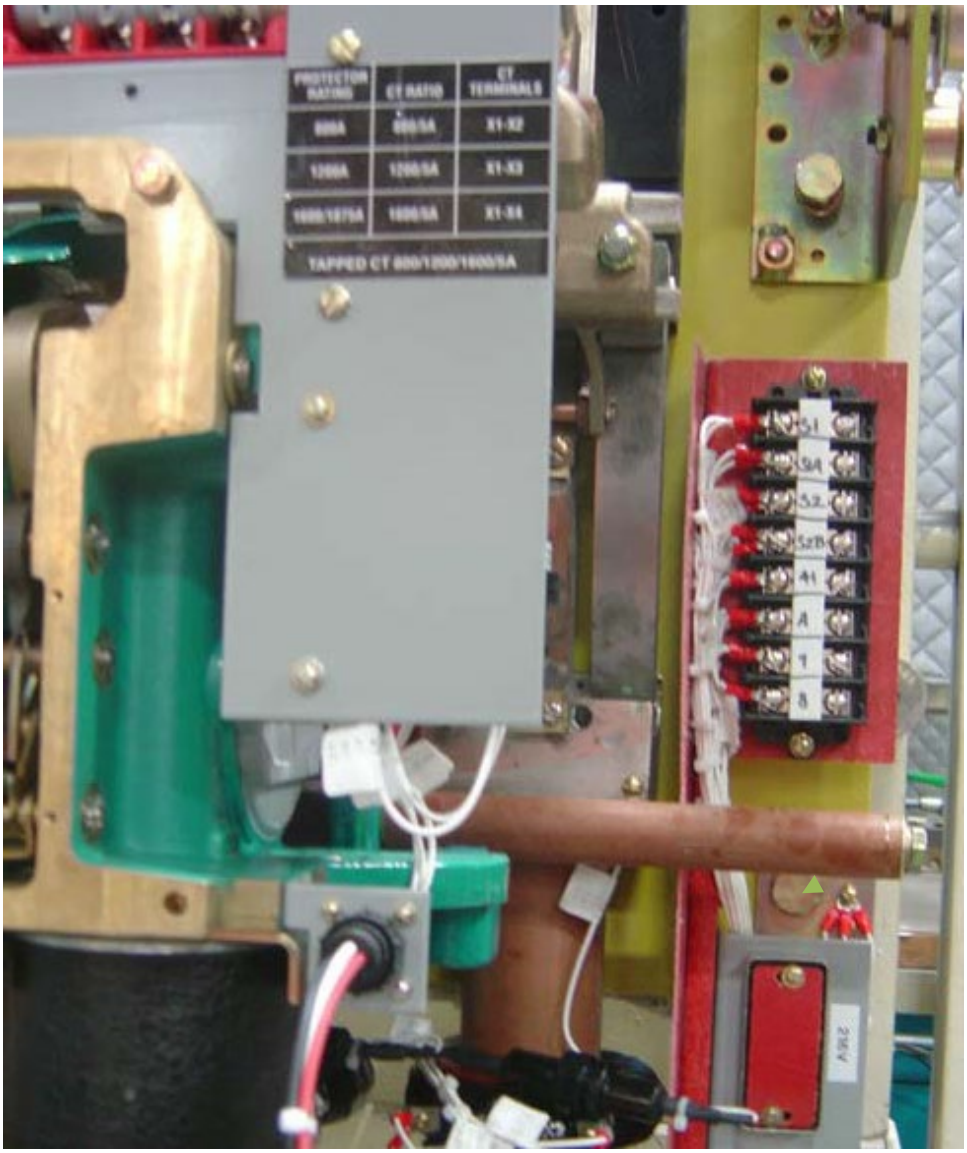


Figure 1 – The Grounding Bolt

24. Install the rail extensions, ensuring they are locked in place, and move the rollout unit from the housing.

Breaker Mechanical Inspection:

1. Record the counter reading.
2. Check for broken or damaged barriers on breaker and housing.
3. Check for any signs of liquid entry into enclosure, transformer throat, etc.
4. Check for indication of overheating, including discoloration of low barrier boards, or a greenish brown paraffin-like substance at the bottom of the

enclosure. This may indicate degradation of the insulation back board. Record any findings.

5. Mechanism Roller Test - Ensure that the roller on the mechanism turns freely to ensure proper closure of contacts. Use a light oil to ensure proper lubrication.
6. Use a drop of oil on all mechanism pins.
7. Verify that the mechanism insulation caps are in place.
8. Inspect and clean the motor housing race of the mechanical 2 lead motors only.
    a) Inspect the motor and brushes for wear. Clean and lubricate these parts as necessary.
9. Inspect for loose wiring at control components:
    - Motor control relay
    - Resistors
    - Terminals
    - Auxiliary switches
10. Check for frayed, cracked, or damaged control wire. Asbestos coated wiring or older wire harness may require an additional dielectric test to determine if it has reached its useful life. See Dielectric Testing.
11. Check for loose hardware.
12. Inspect the bumper on the back of the movable relay mechanism assembly to ensure it is in place and in good condition.
13. Inspect the air dashpot, if so equipped, and clean and lubricate as necessary.
14. Inspect the auxiliary switches (behind the cover) and motor contacts for excessive contact wear.
15. Fuse Inspection: (See Figure 2.)
    a) For the Y and Z fuses:
        - Examine the fuse element to ensure that no visible cracks are present in the element or signs of slow melt.
    b) For the alloy fuses:
        - Examine the fuse element to ensure that no visible cracks are present in the element or signs of slow melt.
        - Place the fuse flat on the top surface of the housing door.
        - Ensure that the fuses rock. Discard any alloy fuses that are annealed flat, thus eliminating the required spring action.

Note: 480Y/277 Voltage units alloy fuses (shown on left) require the extended arc horn and addition barrier to properly clear the phase. Fuses are embossed with the style number that correlates to ampere and curve characteristics.

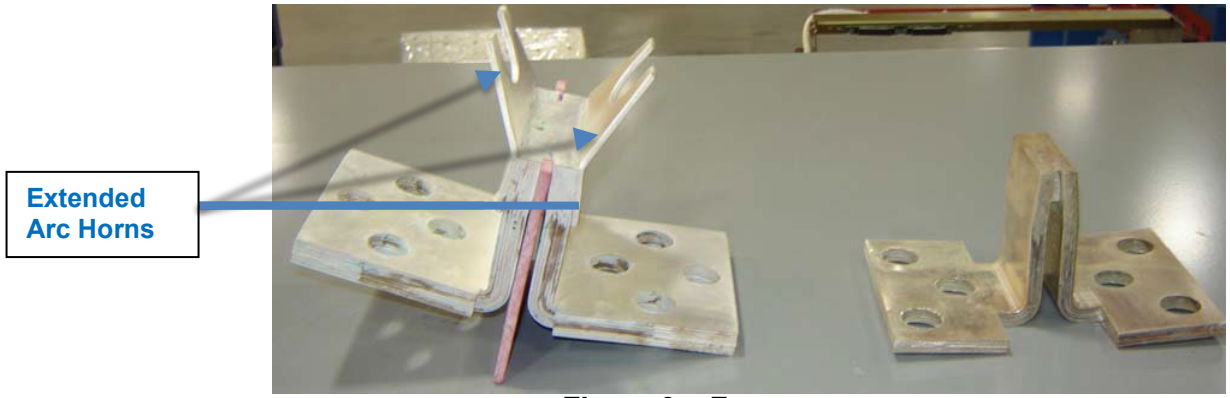


Figure 2 – Fuses

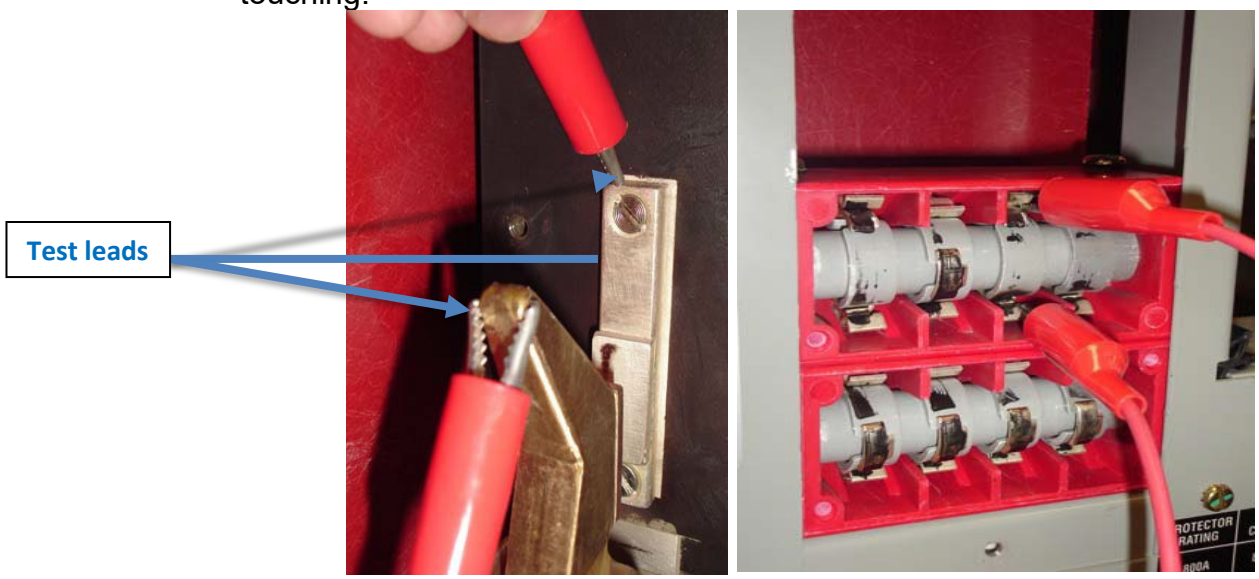
CAUTION: Some arc chutes are made from asbestos. Use hazardous material handling procedures for these.

16. Remove the arc chutes and inspect the contacts.

CAUTION: *Do Not* clean those arc chutes made from asbestos. Replace them instead.

- Arc chutes must be free and clear of any carbon buildup. Clean as necessary.
- Suspect contacts require an additional Micro-Ohm test to verify the resistance level. See Micro-Ohm section.

17. Arc Contact Timing Test. See Figures 3 and 4.
This test is critical to determine if the linkages are set properly and to ensure the auxiliary trip “a” contact picks up prior to the arcing contact touching.



Figures 3 and 4 – The Arc Contact Timing Test

18. Check the cross bar insulation and ensure that there is no build up on the backboard between phases. The backboard integrity and cross bar require an Insulation Resistance test, which is described in the Insulation Test section.
19. Check for melted paraffin in bottom of the enclosure which indicates possible deterioration of the backer board.
20. Remaining verification testing will be done with MECHANICAL TESTING and RELAY TESTING. Please see appropriate sections for testing descriptions and the steps required for proper execution.

Test Sequence: The following sections are a series of tests defined to ensure proper operation at normal condition and at fault duty. It is important to perform the following tests in *this* order:

Test 1 – Manual Breaker Operation Test

Test 2 – Insulation Resistance Test (Megger)

Test 3 – Micro-Ohm Test (Ductor)

Test 4 – Mechanical Electrical Test (Voltage Only Testing

Test 5 – Relay Tests

Test 6 – Ground Fault Test (For 480V Units Only)

Test 1 – Manual Breaker Operation Test

1. Operate the breaker manually while it is on rails using an external closing prop on the handle. Close and trip the breaker 5 times to verify proper mechanical operation. At least one of these tests should be performed with the protector in its enclosure with the fuses and links removed.

Test 2 – Insulation Resistance Test (Megger)

The CM-22 breaker is constructed upon a common insulated back board and requires periodic insulation integrity checks to ensure proper isolation. In addition, the breaker construction relies upon an insulated cross bar that ties all 3 phases together and must be periodically checked to ensure compliance.

1. Remove all potential leads from the breaker bus.
    - The top is the Network side.
    - The bottom is the Transformer side.

2. Using at least a 1,000 VDC Megger, complete the 9-point test outlined in the chart below: An acceptable value is 10 Meg Ohms or greater for a 1 minute time duration.

Backboard Insulation			
Breaker Position OPEN			
Reading Location	N1 to T1	N2 to T2	N3 to T3
Inspection Value			
Crossbar Insulation			
Breaker Position CLOSED			
Reading Location	N1 to GND	N2 to GND	N3 to GND
Inspection Value			
Crossbar Insulation			
Breaker Position CLOSED			
Reading Location	N1 to N2	N2 to N3	N3 to N1
Inspection Value			

Test 3 – Micro-Ohm Testing (Ductor)

Perform an as-found and then after cleaning, a final ductor test. The maximum acceptable value for ductor testing is 25 micro-ohms or less, using a 100 Amp ductor.

1. With the breaker closed, connect the micro-ohm test leads to the network protector.
2. Test and record the value.
    - If the micro-ohm reading is greater than 25 micro-ohms:
        - ❖ Open the breaker and clean the contact surface with Scotch Brite.
        - ❖ Re-test and record the “as-left” value.

Test 4 – Mechanical – Electrical (Voltage Only) Testing

This is a test of minimum acceptable values using 2 phases of the control circuitry.

Mechanical testing is defined as a “voltage only test” without the use of any network relays (electro-mechanical, solid state or digital). This testing is defined in the IEEE standard for Network Protectors C57.12.44. The basis for this type of testing is the minimum trip and close criteria required.

1. Remove all Network Relays.
    - The phasing relay position type (CNJ) must be jumpered out with the relay removed. (Points 4 & 5 on the relay terminal block)
    - The use of a CNJ jumper plate may be required.

CAUTION! - Failure to connect the leads in the correct sequence will cause damage to the Network Protector Test Set.

Reminder: Proper PPE must be worn while attaching leads to an energized bus.

2. Connect the Test Set according to manufacturer's instruction manual and local system operating conditions (phasing).

MIN CLOSE TESTING

1. Apply full system voltage with the test set to ensure closure when the CLOSE button is pressed on the TEST SET.
2. Trip the breaker with the trip lever (Repeat steps (1) and (2) 5 times at full voltage.)
3. Apply 73% of the L-L system voltage. See Table 1. The breaker should NOT close at this level. If the breaker closes, the motor control relay will need adjustment.
    - Older NPs contain a "SG" type open contact motor control relay. There is a center screw on the relay for mechanical contact separation and adjustment. Increase the contact gap for more resistance and stop pickup at 73% level
    - Newer CM-22 designs have an encapsulated motor control relay and use an adjustable resistor on the relay for the same purpose.
4. Apply 80% of the L-L system voltage. The breaker should close.

Table 1 Test Values

Test	%	125/216V	277/480V
a) Minimum Trip	7.5%	16.2V or Less	36.0V or Less
b) Minimum Motor Close Voltage	73%	158V or Less	350V or Less
c) No Pickup (Motor Relay)	73%	158V or Less	350V or Less
d) Min Pickup (Motor Relay)	80%	160V – 173V	354V – 384V

MIN TRIP TESTING

1. With the breaker closed, apply 7.5% of system voltage (16 Volt (216), 36 Volts (480).
2. Depress the TRIP button on the test set.
    - If the CM-22 does not trip at this level, then a sensitivity adjustment is needed on the shunt trip level assembly. The adjustment screw is located behind the swing relay panel. See Figure 6. Access to the screw is given by a hole in the bottom red insulation barrier on the swinging door panel. It is best to remove the motor to view the screw. Any adjustment vertically will make the mechanism more sensitive to trip.

NOTE: To initially set this device, perform the following:

a. Manually close the breaker.
b. Adjust this screw upward until the breaker opens.
c. Turn the screw back down 1 turn after the opening.
d. Lock down the top lock nut.
e. Re-test the min level to determine if this adjustment fits the trip range.

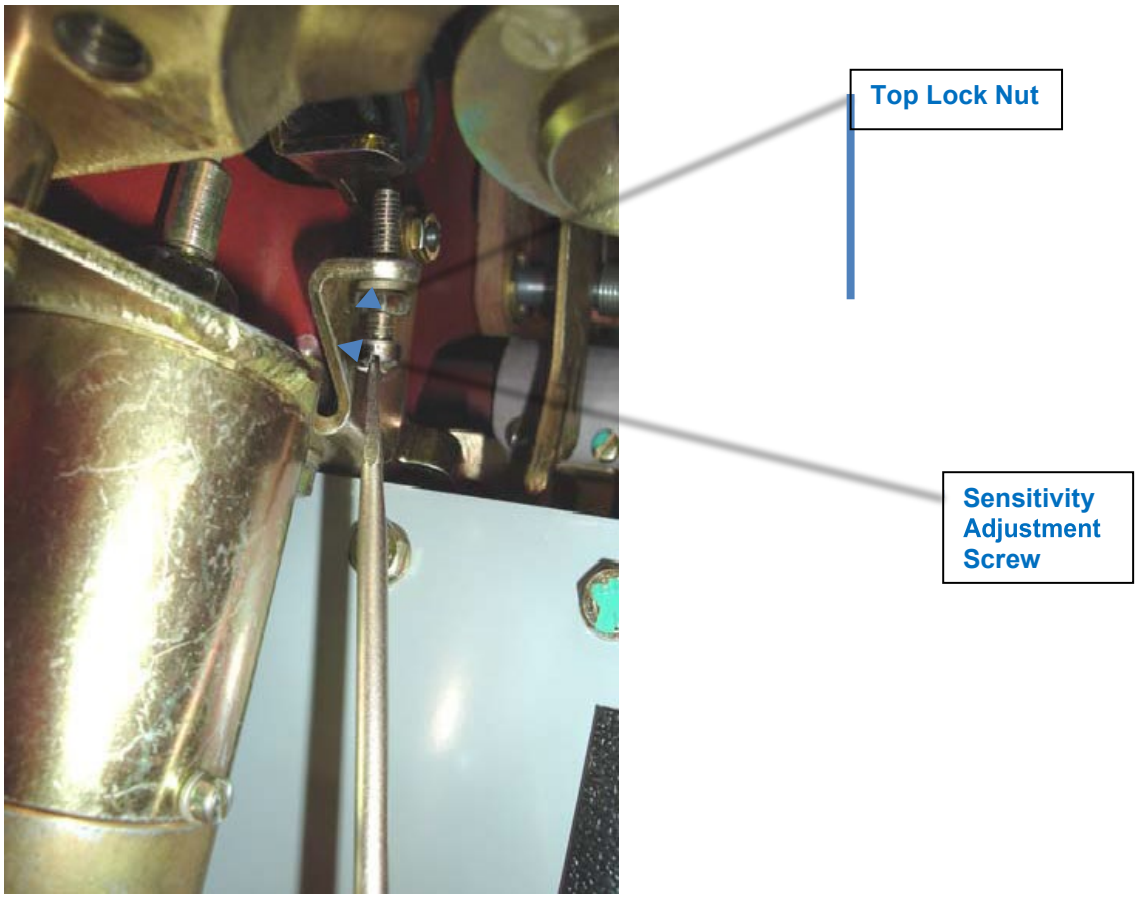


Figure 6 – Trip Screw Adjustment

Test 5 – Relay Tests

Electro-mechanical Relay Tests

1. Perform the Master Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
   - Network Protector Test Set Instructions
   - Relay Instructions
   - Network Protector Instructions

2. Perform the Phasing Relay Overvoltage test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
3. Perform the Reverse Current LimitingTrip test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
4. If a BN relay is installed, perform the Timing test and adjust the relay as necessary in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
    -

Test 5 – Relay Tests (continued)

Solid State / Microprocessor Relays

1. Perform an Overvoltage test and adjust the relay in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
2. Perform a Reverse Current Trip test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions
3. If a Time Delay is used, perform a Time Delay test in accordance with the following documents. Record the As-Found and As-Left values.
    - Network Protector Test Set Instructions
    - Relay Instructions
    - Network Protector Instructions

Test 6 – Ground Fault Test (480V units only)

CAUTION: The ground fault protection circuit between the protector and the customer main service is owned and maintained by the customer. Testing the lock out may call for all protectors to trip. An up-to-date drawing must be made available and reviewed to determine those steps which must be taken to prevent tripping of all protectors.

Verify trip from lockout and block the close of the protectors on all units having a ground fault scheme.

NOTES:

1) The Ground Fault system is typically Customer-owned, and the Lockout is typically Eversource owned. It is important to have an up-to-date print of the scheme prior to performing a test.
2) This test is only to be performed on those units equipped with a ground fault system.

CM-22 Re-install Procedure

1. Roll the unit back into the housing to its installed position.
2. With an insulated wrench, tighten the ground bolt first and then secure other bolts into place.
3. With the protector breaker in tripped position, use test probe (Stock Code 441607) with a 1 amp or 5 amp current limiting fuse (KTK-1 or KTK-5) in accordance with the manufacturer's instructions to ensure that a short circuit does not exist in the network protector. See Figure 7.

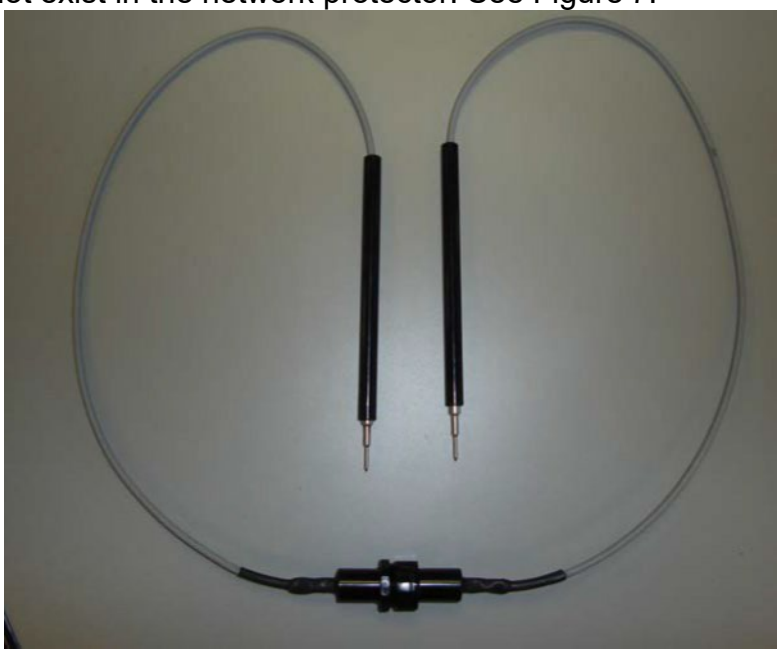


Figure 7 – Test Probe Placement

4. Apply anti-seize grease to the door bolt hardware.
5. Check the door gasket to ensure it is still in good condition.
6. Apply gasket preservative to the door gasket.
7. Tighten all door bolts (The tank is secure once the 2 jam (stop) nuts touch tank.) **NOTE**: Use of impact tools is not recommended and could lead to moving stop nuts for proper sealing and premature door gasket damage.)
8. Check condition of external tank. Check cooling fins to ensure that they are not clogged, missing, or in need of replacement.

9. Verify the protector enclosure is holding pressure using a pressure gauge/fill device. If it is not, perform a **leak check** on those network protectors with submersible enclosures as follows:
    a) Pressurize the enclosure with 5 PSI of dry nitrogen.
    b) Apply a soap solution to the door gaskets, enclosure penetrations, throat gaskets, operating handle gaskets, welds, etc.
    c) Let this sit for 30 minutes.
    d) Check for leaks by looking for soap bubbles. Fix any leaks if possible.
    e) Record any leaks on the inspection form and alert supervision.
    f) Reduce the pressure within the enclosure to 1.5 PSI.
10. Place the operating handle in as-found position.
11. Read and record the as-left counter reading.

APPENDIX 14

APPENDIX NO LONGER USED

APPENDIX 15

UNDERGROUND TRANSFORMERS

5.55 Underground Transformers

General Description Loads fed from the underground system that are not tied to the network grid are supplied from either single-phase transformers, banks of single phase transformers, or three-phase transformer units. These pad-mounted transformers are usually of an underground or submersible type. Transformers that were installed years ago had various types of cable entrances to accommodate the various types of insulated cables that were installed. They could be fed from underground cables or from a riser. The transformers were generally protected on the high voltage side with either external fuses or internal fuses. The system voltages were generally 5kV and below. Many of these transformers have been replaced over the years as 5kV and below systems have been converted to systems ranging from 15kV to 35kV. Single phase transformers installed in these conversion areas and in new underground areas are the standard manhole or vault type transformer. These submersible transformers have internal fuses on the high voltage side and secondary breakers on the low voltage side. Industry standard rubber molded products are used to connect the transformers to insulated primary cables made of newer materials.

NOTE: All specific maintenance requirements that are followed by a triangle symbol "▲" are explained in the Maintenance Basis Documentation section of this chapter.

5.55.1 Inspection and Maintenance Activity Schedules

5.55.1.1 Table 1 – Underground Transformer Maintenance Intervals

UNDERGROUND TRANSFORMER **Maintenance Schedule**	**All Models**
PM Task	
Condition Monitoring	N/A
Time-Directed	
Routine Inspection – Energized ▲	A/R or max 15Y
Condition-Based	
Infrared Inspection (**Note 1**)	A/R
Correct any defects found during Routine Inspection.	A/R
Inspect suspect equipment or conditions previously reported	1YR (Note 2)
Failure Finding	
Equipment Failure Reporting System (EFRS)	A/R
Failure Investigation	A/R
Scheduling Requirements	
Perform together with underground system (radial) - cable	

In **Table 1**, the intersection of the row and column indicate the inspection or maintenance interval for the equipment in the column heading. For example, the interval for a Routine Inspection for all models of Underground Transformers is maximum 15Y (or Fifteen years). The abbreviations used for the intervals are:
Y = Year, i.e. 1Y = 1 year
A/R = As Required

NOTE 1 = Infrared surveys are performed on Underground Transformers in accordance with EMP Chapter 5.22 – Infrared Inspections. Refer To EMP Chapter 5.22 – Infrared Inspections for inspection requirements and the interval at which inspections are to be performed.
NOTE 2 = Equipment or conditions may exist that require monitoring on a basis more frequent than maximum 15Y Routine Inspection.

5.55.2 Underground Transformer Maintenance Categories

TIME-DIRECTED

5.55.2.1 Routine Inspection – Energized ▲

1. See EMP Instructions 6.55 for detail steps

CONDITION-BASED

5.55.2.2 Infrared Inspection – Refer to EMP Chapter 5.22 for inspection requirements and intervals.

5.55.3 Failure Finding - Failures of Underground Transformers shall be documented in the equipment failure reporting system used by your region. A failure report shall be completed for any underground transformer failure and placed in “To Eng” status for review by Distribution Standards. Analysis of underground transformer failures should be performed when deemed necessary by Distribution Standards.

5.55.4 Underground Transformer References:

- Electric Utility Line Maintenance Plan
- EMP (the Eversource Maintenance Program)

5.55.5 Underground Transformer Maintenance Basis Documentation The maintenance activities and their schedules are based on company past practices, and the subject matter expert who is a Senior Engineer for Distribution Engineering and Design.

Requirement	Basis
Routine Inspection – Energized A/R or Max 15Y interval.	Move to a condition/reliability-based inspection. Frequency will depend on previous fault history and/or known environmental conditions. The maximum inspection period will align with other DB inspections and fault indicator replacement.
Infrared Inspection	Infrared inspection is a proven technique for locating "hot spots" on equipment and connections in order to identify conditions that can be corrected before they become serious problems.

6.55 Underground Transformers Instructions

Before You Begin

Prior to assigning work in Underground Vaults & Manholes, Supervision shall:

1. Ensure that all employees are properly trained and qualified to perform this work, and that all appropriate PPE and safety requirements are met, including but not limited to those defined within the following documents:
   - TD 211, "When to Wear FR Clothing"
   - TD 952, "Protection of Personnel Entering Enclosed Spaces" (Connecticut and Western MA only)
   - TD 955, "Confined Space Requirements"
   - Eversource Employee Safety Manual
2. Ensure those performing the work are aware that of the following PPE requirements whenever working in Underground Vaults & Manholes:
   - Safety Glasses with side shields
   - EH (Electrical Hazard) rated boots
   - High Voltage gloves
   - FR(flame resistant) clothing, as specified in TD 211
3. Job Setup: Work zones, requirements for various jobs, switching requirements. All arrangements should be completed or setup prior to beginning the job. These include cones, signage, and police or traffic control. Check holes prior to entry for cleaning needs, i.e. pumping water, debris, contaminates, visible oil, and providing samples for lab analysis.
4. Review the manufacturer's manuals for all safety notations (Danger,

Warnings, and Cautions), as needed. These may be in sections of the manual other than with the instructions.

5. Prepare the vault for entry.
    a) Check for dangerous atmospheric conditions before entering the vault using company-approved atmospheric sampling equipment.
    b) Ventilate the vault, if required, in accordance with the Eversource Employee Safety Manual.
    c) Remove any standing water or debris from the vault in accordance withENVIROWI-0105 or company-specific requirements, as required. This is located in the Environmental and Facility Procedures section of the Distribution Engineering Standards Bookshelf.

Equipment Covered by This Section

- Underground Transformers – Dead Front
- Underground Transformers – Live Front

Routine Inspection – Preparation

Supervisor, Planner, or Working Foremen (as appropriate)

1. Check for open work orders (such as leaking splices) for this location that may indicate unsafe conditions or that may present the opportunity for combining maintenance at this or adjacent vaults. Ensure Copies are provided to the crew performing the inspection.
2. Provide equipment prints / schematics / circuit maps for this location so that the actual field conditions, i.e. transformer size, etc. can be verified by the crew performing the inspection.

Routine Inspection – Performance

Inspection Crew

> **CAUTION**
> Special precautions need to be taken when performing inspections on Live Front transformers. Review the Eversource Employee Safety Manual for specific safety requirements and operating company specific procedures.

1. Check for stray voltage in accordance with EMP 6.62 - Touch Potential.
2. Verify the actual field conditions, i.e., transformer size, etc. using the equipment prints /schematics / circuit maps.
3. Ensure equipment nomenclature, standard signs, cable tags, labels, and status indicators are present and in good condition. Clean as required and replace missing cable ID tags with brass tags. Plastic tags may be used in addition to the brass tags.

> **CAUTION**:
> Before replacing missing tags, BE SURE you have the correct information to put on the tag. Use appropriate procedures and circuit maps / prints for identification.

4. Check the nameplate for presence of PCBs within the equipment. This will be indicated by a blue or green label. Note the presence of PCBs or the absence of a sticker indicating this information.
5. Observe the exterior of the transformer for any other significant defect or abnormal condition that may affect the safe operation of the unit, such as excessive damage /corrosion to the unit or other defect that requires immediate repair.

> **NOTE**:
> Entry into the transformer must be prevented. Any hole from corrosion or other damage must be blocked to prevent intrusion and possible harm to the public.

6. Ensure safety and security equipment (such as brass locks and penta-bolts) are in place and in good working condition. Check for signs of vandalism.

> **NOTE:**
> Any transformer that cannot be locked due to rusted or broken locking hardware must be secured to prevent public entry. If the transformer cannot be secured, replace it immediately.

7. Ensure the transformer includes spare fuses (if practiced by your operating company).
8. For Live front Transformer units, ensure electrical barriers (i.e. baker board) are in place.

> **NOTE**:
> Removal of barriers (i.e. baker board) for the purpose of performing an inspection in the primary compartment shall be done using appropriate PPE in accordance with Safety rules / requirements and operating company specific procedures.

9. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition. Refer to Underground Standards sections 56 and 58 for grounding requirements.
10. Ensure that primary / secondary equipment such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead-end receptacles are present and in in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.

> **NOTE:**
> Treat load break elbows (if present) with missing test caps as “live front” until the elbow test caps are replaced according to manufacturer’s recommendations. Tag the transformer as needing repair until the elbow test caps are replaced. New Hampshire personnel should refer to New Hampshire Procedure CO-1004 Load-Break Elbow Procedure.

11. Ensure all fault indicators (as applicable) are in good condition and working. Replace them every fifteen years or as necessary.
12. Ensure all gauges are in good condition and working, if present. These may include those for temperature, oil level, etc.

13. Inspect equipment for signs of oil leaks.
14. Visually check the oil level, if practical.
15. Ensure deflector plates are installed, as required for the specific equipment type (varies by operating company). Deflector plates are shields installed over some submersible transformers.
16. Check for the presence of anodes and the condition of their connections, as applicable for three phase transformers or network protector installation in below grade vaults. See Underground Standards sections 013 and 015-016 for anode requirements.

Underground Transformer Workers Aid
Routine - Energized
EMP 6.55-1
Guideline

	Inspect	Inspection Attributes
1.	Stray Voltage	Check for stray voltage in accordance with EMP 6.62 - Touch Potential.
2.	Verify field conditions	Verify the actual field conditions, i.e., transformer size, etc. using the equipment prints / schematics / circuit maps.
3.	Nomenclature And Status Indicators	Ensure equipment nomenclature and status indicators are present and in good condition. Clean or replace as required. Ensure the work order matches the ID tag and that all identification and location numbers are correct.
4.	PCB's	Check the nameplate for presence of PCBs within the equipment. This will be indicated by a blue or green label. Note the presence of PCBs or the absence of a sticker indicating this information
5.	Significant Defect Or Abnormal Condition	Observe the exterior of the transformer for any other significant defect or abnormal condition that may affect the safe operation of the switch, such as excessive damage / corrosion to the unit or other defect that requires immediate repair.
6.	Wire Connections	Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition. Refer to Underground Standards sections 56 and 58 for grounding requirements
7.	Primary /Secondary Equipment	Ensure that primary / secondary equipment such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead end receptacles are present and in in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.
8.	Fault Indicators	Ensure all fault indicators (as applicable) are in good condition and working. Replace them every ten years or as necessary
9.	Oil Level & Pressure	Ensure all gauges are in good condition and working, if present. These may include those for temperature, oil level, etc. Visually check the oil level, if practical. Inspect equipment for signs of oil leaks..
10.	Deflector Plates	Ensure deflector plates are installed, as required for the specific equipment type
11.	Anodes	Check for the presence of anodes and the condition of their connections, as applicable for three phase transformers installation in below grade vaults. See Underground Standards sections 013 and 015-016 for anode requirements
12.	Infrared Inspection	Perform an infrared inspection to check for heat anomalies on primary connections, secondary connections and accessories, as applicable. Refer to EMP 5.22 for additional guidance

APPENDIX 16

STREET LIGHTING

EMP 5.48 STREETLIGHTS

1.0 Introduction

1.1 Streetlight maintenance includes the Time-Directed (preventive) and Condition-Based maintenance which includes the troubleshooting and repair of lights that have failed. This document provides the intervals for time-directed maintenance for all municipalities.

1.2 For Non-LED Streetlights:

1.2.1 The term “Lamp” refers to the bulb that actually illuminates.

1.2.2 The term “Fixture” refers to streetlights. It includes the assembly into which the lamp and photocontrols are installed.

1.3 For LED Streetlights:

1.3.1 LED streetlights do not require the use of a “Lamp” as the LEDs are integrated into the “Fixture”.

1.3.2 Photocontrols shall be installed for LED streetlights.

1.4 It is important to label the inside of the fixture with date of installation for record keeping and for an indication of maintenance check.

1.5 **Appendix A** contains the operating hours for LED streetlights and the operating hours of Optional Midnight Service respectively for all three states according to their respective currently approved rates.

2.0 Reference Documents

TD 863	Pole-top Repair of High-Pressure Sodium Luminaires and Flood Lights
TD 223	Regulated Waste Storage
DTR 21.061	Overhead Fed Luminaire Connections Wood Pole − Bracket Mounting
DTR 21.433	Metal Poles - Premium Decorative Lighting Pole W/Receptacle Metal Pole & Luminaire Wiring

ANSI/IES RP-8-21 Recommended Practice: Lighting Roadway and Parking Facilities

3.0 Definitions

3.1 The abbreviations used for the intervals are:

3.1.1 **Y** = Year, i.e. 2Y = 2 Years

3.1.2 **A/R** = As Required

4.0 Inspection and Maintenance Schedules

4.1 Any failed lamps or NON-LED fixtures shall be disposed of in accordance with **TD 223** and replaced with an equivalent LED fixture.

4.1.1 Existing inventory of NON-LED lamps and fixtures shall be depleted and used prior to installation of LED fixtures.

4.1.2 Prior to installation of any LED fixtures, each operating state shall refer to their corresponding currently approved rate to identify which LEDs are currently approved in their rates.

Table 1 – Streetlight Maintenance Intervals

LED Street Light Maintenance Schedule	Interval
Time-Directed	
Replace Fixture	15Y
Inspect Metal Streetlight Pole	15Y
Condition-Based	
Perform Troubleshooting Based on Malfunction	A/R
Replace Fixture	A/R

5.0 Maintenance Categories

5.1 Time-Directed

5.1.1 Fixtures are to be replaced on a 15 YR scheduled basis before they fail in order to provide continuous service and eliminate the cost of emergency repairs.

5.1.2 Western Massachusetts does not perform Time-Directed Maintenance; instead, they perform Condition-Based Maintenance.

5.2 Condition-Based

5.2.1 See **TD 863** for details on troubleshooting streetlight problems and the handling of waste materials.

6.0 Failure Findings

6.1 Report each fixture that has been disconnected at the end of the workday to your supervisor.

6.2 Non-LED streetlights must have the lamp removed. The lamp is to be placed in the appropriate environmental disposal container. The fixture, with no lamp, is to be disposed of in the scrap metal dumpster (or streetlight dumpster if one is available at the facility or job site).

6.3 LED fixtures are to be disposed of in the scrap metal dumpster.

6.4 Any failures found during maintenance should be recorded and provided to Supervisor and to Street Light Account Executive or Customer Service for follow-up.

6.5 The responsibility for cost of repair of lighting fixtures varies with each operating company. Documentation specific to each company should be referenced where appropriate.

7.0 Streetlight Maintenance Basis Documentation

7.1 According to RP-8-21, the industry standard for LED end of life is the point at which light output has reached a percentage of its initial output, usually 70%. This is reported as the L70 value.

7.1.1 L70 is the time (in hours) when the light output from the LED has dropped to 70 percent of its initial output.

7.1.2 The rated lumen-maintenance life of an LED is the elapsed operating time over which an LED light source maintains a given percentage of its initial lightoutput.

7.1.3 LEDs do not typically fail outright but instead continually fade.

NOTE: The time when the rated lumen maintenance life of an LED light source is reached is dependent on many variables, including the operating temperature, the drive current, and the technology and materials used to construct the products. As such, the lumen maintenance of LEDs can vary not only from manufacturer to manufacturer, but also between different LED package types produced by a single manufacturer.

7.2 According to both currently approved manufacturers Cooper Lighting and American Electric Lighting, the operating hours of the driver in LED streetlights are 100,000 hours and LEDs' L70 value is greater than 100,000 hours at 25 degrees Celsius.

7.3 **Table 2** shows the maintenance interval based on operating hours of the driver for LED fixtures.

Table 2 – Maintenance Interval based on operating hours for LED Streetlights.

Maintenance Interval			
Connecticut	**Eastern Mass.**	**Western Mass.**	**New Hampshire**
24 years	23.8 years	24 years	25.3 years

7.4 **Table 3** shows the expected life of LED fixtures and photocontrols and their respective estimated annual failure rate based on information received from Cooper Electric Lighting.

Table 3 – Expected lifetime and Annual Failure Rate

Expected Lifetime		Annual Failure Rate	
LED Streetlights	Typically, greater than 20 years	LED Electronics	Typically, 1%
		LED Lumen Depreciation	Typically,1-2%
Photocontrol	Typically, greater than 10 years	Photocontrol	Anticipated less than 1-2%

7.5 The maintenance activities and their schedules are based on industry Standards, manufacturer's recommendations, and Field experience.

Table 4 – Streetlight Maintenance Basis Documentation

Requirement	Basis
Maintenance	• A 15Y interval is recommended by approved manufacturers • ANSI/IES RP-8-21 guidelines and industry standard L70 – LED rated lumen maintenance life of an LED light source. • In addition to the expected lifetime of LED fixtures, expected lifetime of components within or installed on the fixture were taken into consideration. Refer to **Tables 2-3** and **Appendix A**. • A shorter Time-Directed interval is optional at the discretion of each operating company.

Appendix A

Appendix A, Table 1 – Operating Hours for LED Streetlights

Month -	Operating Hours (CT) -	Operating Hours (MA)				Operating Hours (NH)* -
		Greater Boston	Cambridge	South Boston	WMA	
January	433	439	418	418	433	421
February	365 (377)	367	355	355	365 (377)	350 (362)
March	364	364	347	347	364	342
April	310	310	296	296	310	286
May	280	284	270	270	280	257
June	251	257	244	244	251	230
July	269	275	260	260	269	248
August	301	307	292	292	301	283
September	334	338	321	321	334	316
October	388	392	373	373	388	372
November	413	417	396	396	413	399
December	442	450	428	428	442	433
Total	**4,150 (4,162)**	**4,200**	**4,000**	**4,000**	**4,150 (4,162)**	**3,937 (3,949)**

NOTE: The numbers in parenthesis indicate operating hours for a leap year for each state.

* The operating hours for NH were based on rate EOL.

Appendix A, Table 2 – Operating Hours of Optional Midnight service for LED Streetlights

Month	Operating Hours (CT)	Operating Hours (WMA)*	Operating Hours (NH)**
January	224	224	213
February	185 (192)	185 (192)	175 (181)
March	187	187	150
April	164	164	120
May	153	153	106
June	137	137	91
July	144	144	97
August	161	161	116
September	181	181	138
October	213	213	170
November	225	225	214
December	236	236	226
Total	**2,210 (2217)**	**2,210 (2217)**	**1,816 (1,822)**

NOTE: The optional Midnight service can be elected by customers for those who want the fixture to turn off at midnight.

* There are no operating hours of optional midnight service for LED streetlights for Eastern Massachusetts.

** The optional midnight service operating hours for NH were based on rate EOL.

NOTE: The time when the rated lumen maintenance life of an LED light source is reached is dependent on many variables, including the operating temperature, the drive current, and the technology and materials used to construct the products. As such, the lumen maintenance of LEDs can vary not only from manufacturer to manufacturer, but also between different LED package types produced by a single manufacturer.

7.2 According to both currently approved manufacturers Cooper Lighting and American Electric Lighting, the operating hours of the driver in LED streetlights are 100,000 hours and LEDs' L70 value is greater than 100,000 hours at 25 degrees Celsius.

7.3 **Table 2** shows the maintenance interval based on operating hours of the driver for LED fixtures.

Table 2 – Maintenance Interval based on operating hours for LED Streetlights.

Maintenance Interval			
Connecticut	**Eastern Mass.**	**Western Mass.**	**New Hampshire**
24 years	23.8 years	24 years	25.3 years

7.4 **Table 3** shows the expected life of LED fixtures and photocontrols and their respective estimated annual failure rate based on information received from Cooper Electric Lighting.

Table 3 – Expected lifetime and Annual Failure Rate

Expected Lifetime		Annual Failure Rate	
LED Streetlights	Typically, greater than 20 years	LED Electronics	Typically, 1%
		LED Lumen Depreciation	Typically,1-2%
Photocontrol	Typically, greater than 10 years	Photocontrol	Anticipated less than 1-2%

7.5 The maintenance activities and their schedules are based on industry Standards, manufacturer's recommendations, and Field experience.

Table 4 – Streetlight Maintenance Basis Documentation

Requirement	Basis
Maintenance	• A 15Y interval is recommended by approved manufacturers • ANSI/IES RP-8-21 guidelines and industry standard L70 – LED rated lumen maintenance life of an LED light source. • In addition to the expected lifetime of LED fixtures, expected lifetime of components within or installed on the fixture were taken into consideration. Refer to **Tables 2-3** and **Appendix A**. • A shorter Time-Directed interval is optional at the discretion of each operating company.

Appendix A

Appendix A, Table 1 – Operating Hours for LED Streetlights

Month -	Operating Hours (CT) -	Operating Hours (MA)				Operating Hours (NH)* -
		Greater Boston	Cambridge	South Boston	WMA	
January	433	439	418	418	433	421
February	365 (377)	367	355	355	365 (377)	350 (362)
March	364	364	347	347	364	342
April	310	310	296	296	310	286
May	280	284	270	270	280	257
June	251	257	244	244	251	230
July	269	275	260	260	269	248
August	301	307	292	292	301	283
September	334	338	321	321	334	316
October	388	392	373	373	388	372
November	413	417	396	396	413	399
December	442	450	428	428	442	433
Total	**4,150 (4,162)**	**4,200**	**4,000**	**4,000**	**4,150 (4,162)**	**3,937 (3,949)**

NOTE: The numbers in parenthesis indicate operating hours for a leap year for each state.

* The operating hours for NH were based on rate EOL.

Appendix A, Table 2 – Operating Hours of Optional Midnight service for LED Streetlights

Month	Operating Hours (CT)	Operating Hours (WMA)*	Operating Hours (NH)**
January	224	224	213
February	185 (192)	185 (192)	175 (181)
March	187	187	150
April	164	164	120
May	153	153	106
June	137	137	91
July	144	144	97
August	161	161	116
September	181	181	138
October	213	213	170
November	225	225	214
December	236	236	226
Total	**2,210 (2217)**	**2,210 (2217)**	**1,816 (1,822)**

NOTE: The optional Midnight service can be elected by customers for those who want the fixture to turn off at midnight.

* There are no operating hours of optional midnight service for LED streetlights for Eastern Massachusetts.

** The optional midnight service operating hours for NH were based on rate EOL.

APPENDIX 17

UNDERGROUND VAULTS AND MANHOLES

1.0 Abbreviations

1.1 CT-DOT: State of Connecticut – Department of Transportations.

2.0 Maintenance Basis Documentation

2.1 The preventative maintenance activities and schedules outlined within this document are based on industry experience and/or best practice, manufacturer's recommendations, past company practices and inputs from Subject Matter Experts from Engineering, Operations, Field Engineering and T&D Standards.

2.2 Maintenance Activity Basis

Requirement	Basis
Major Distribution Level Inspection	Eversource Distribution manhole/vault and their equipment shall be inspected at a frequency of 10 years in Eversource system except for Boston proper, where the frequency is 4 years[1]. Routine Inspections of vault and manhole structures, anodes, and sump pumps (if exist) shall be visual inspections. Hammer testing may be used as needed. This inspection should be performed coincident with equipment maintenance frequencies. The inspection schedules and reports shall be maintained in **MAXIMO**.
Major Transmission Level Inspection	The inspection frequency to perform civil structural manhole/vault and cable system is 5 years in Eversource system except for Boston proper, where the frequency is 4 years[1]. **Note**: The inspection of the manholes listed by CT-DOT letter (see attachment 1) shall include hammer testing and approved by a CT Licensed Professional Engineer. All other Manhole/Vault structure's routine inspections, anodes, and sump pumps (if exist) shall be visual inspections; however, hammer testing may be used as needed. The inspection schedules and reports shall be maintained in **CASCADE**.
Routine Inspection – As Required	Inspection is performed to determine the condition of the structure and identifies the severity level of the required repairs (C1 through C4) in accordance with WMS 82.01.
Inspection/maintenance of customer-owned manhole/vaults	Customer-owned manholes/vaults shall be inspected coincident with Eversource manhole/vault maintenance frequencies.
Inspection/maintenance of Anodes	Inspection of the anodes shall be planned coincident with existing equipment inspections.

[1] Per DPU Docket EFSB22-01

3.0 Reference Documents

Eversource revised letter to CT-DOT dated March 31st, 2010, agreeing to perform structural integrity inspections of specific vaults located within CT-DOT paved roadways.

MA-DPU Docket number EFSB 22-01.

ESOP100 Switching and Tagging

WMS 82.01 Manhole Inspections and Upgrades

WMS 81.13 Underground Cable and Equipment Thermography

WMS 86.03 Vault Inspection

4.0 General

4.1 All equipment drawings and reference materials shall be reviewed prior to the work in manholes and vaults.

5.0 Inspection and Preventative Maintenance Schedule

Inspection & Maintenance Schedule (Note 1)					
Inspection Type	**Inspection Interval**				
	CT	**NH**	**WMA**	**EMA**	**BOSTON PROPER**
Time-Directed Maintenance (PM & Inspections)					
Major Distribution Level Inspection	10Y	10Y	10Y	10Y	4Y
Major Transmission Level Inspection	5Y	5Y	5Y	5Y	4Y
Condition-Based Maintenance					
C1 Vaults/Manholes – Major Maintenance	A/R	A/R	A/R	A/R	A/R
C2 Vaults/Manholes – Major Maintenance	A/R	A/R	A/R	A/R	A/R
C3 Vaults/Manholes – Major Maintenance	A/R	A/R	A/R	A/R	A/R
C4 Vaults/Manholes – Major Maintenance	A/R	A/R	A/R	A/R	A/R
Routine Inspection (**Note 2**)	A/R	A/R	A/R	A/R	A/R
Correct any defects found during Routine Inspection, if possible	A/R	A/R	A/R	A/R	A/R
Change Condition Rating of work site	A/R	A/R	A/R	A/R	A/R
Condition Monitoring					
Condition Monitoring	N/A	N/A	N/A	N/A	N/A
Failure Finding					
Report defect conditions for underground vaults and manholes	A/R	A/R	A/R	A/R	A/R

Note 1: Defects found during planned maintenance and/or inspection may result in reclassification of the structure conditions as C1, C2 or C3 severity levels as defined in WMS 82.01.

Note 2: **IN NO CASE** shall the period between inspections exceed the frequencies defined in the table above.

6.0 Condition Based Maintenance (CBM)

6.1 Test, assess and prepare the underground vaults and manholes to be safe for entry.

6.2 Condition Based Maintenance shall not exceed the frequency required to ensure the safety of those workers who enter the facilities and the protection of the equipment within.

6.3 Equipment (Cable, switches, Transformers and splices and accessories) shall be performed visually and/or by non- invasive (IR imaging).

7.0 Failure Finding

A failure report shall be completed and placed in the appropriate failure tracking system (Maximo, Cascade, etc.).

ATTACHMENT 1 – CT DOT Letter for Structural Integrity Inspections

Connecticut Light & Power
The Northeast Utilities System

The Connecticut Light and Power Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 947-2000
www.cl-pcom

March 31, 2010

Mr. Thomas A. Harley, Chief Engineer
Connecticut Department of Transportation
Bureau of Engineering and Highway Operations
2800 Berlin Turnpike
Newington, CT 06131-7546

RE: Splice Vault Structural Integrity Inspection Program for the Existing 345/115 kV Transmission Vaults Under Dockets 217, 272, and 292

Dear Mr. Harley:

Attached is the Splice Vault Structural Integrity Inspection Program that we sent to the Department on December 16, 2008, revised to address the design load rating of the splice vaults for the Bethel-Norwalk project (Docket 217). This project was designed prior to the Department initiating the Design Operating Vehicle load requirement, therefore the splice vaults were designed to accommodate the AASHTO HS-20 design vehicle.

Regards,

Anne Bartosewicz
Project Director

c: Joseph Obara – ConnDOT
Sohrab Afrazi – ConnDOT

SPLICE VAULT STRUCTURAL INTEGRITY INSPECTION PROGRAM FOR NORTHEAST UTILITIES VAULTS LOCATED WITHIN ConnDOT ROADWAYS for the MIDDLETOWN-NORWALK 345-KV PROJECT, GLENBROOK CABLES 115-KV PROJECT, and BETHEL-NORWALK 345-KV PROJECT

For splice vaults for the Middletown-Norwalk (MN) and Glenbrook Cables (GC) projects located within ConnDOT roadways, the design and inspection program is to comply with the requirements outlined in the ConnDOT letter dated November 1, 2005 from Art Gruhn, ConnDOT Bureau Chief, to Anne Bartosewicz, NU's Project Director. In summary, the splice vault design for the MN and GC projects shall at minimum accommodate the AASHTO HS-20 design vehicle, and shall be checked for ConnDOT's Design Operating Vehicle, which is a 204 kip, 8-axle vehicle. The Design Operating Vehicle is the critical loading condition and additionally it satisfies the AASHTO HS-25 design vehicle loading condition. The splice vaults for the Bethel-Norwalk (BN) project were designed at a minimum to accommodate the AASHTO HS-20 design vehicle. ConnDOT instituted the Design Operating Vehicle requirement after the BN project was designed and therefore it was not considered in the BN vault design. The inspection requirements include the preparation of inspection reports by a Connecticut licensed professional engineer, and submission of the reports to ConnDOT, all in accordance with ConnDOT's Bridge Inspection Manual (in particular, the Culvert section of the Manual). These inspection requirements are addressed in the following section and apply to the vaults identified in Exhibit A attached hereto, which also includes the vaults installed within the paved roadway of a State highway for the BN project.

INSPECTION FOR STRUCTURAL INTEGRITY

The splice vault inspection for structural integrity will be conducted at an interval no greater than 5 years, with an increased frequency should a defect be identified, and the report shall be signed and sealed by a Connecticut licensed professional engineer. Such an inspection cycle will provide a continuous condition evaluation record of the vault. Should defects be discovered that present a hazard to the safe passage across the vault, ConnDOT is to be immediately notified and appropriate follow-up actions are to be taken. As part of the inspection program, the load rating (live load carrying capacity) is to be computed using the Load Factor Method and updated incorporating the effects of any structural deficiencies. Future ConnDOT requirements may change the load rating computation method to the Load and Resistance Factor Rating method.

The components of the vault are to be evaluated for their current physical state and rated in accordance with the Condition Rating Coding System in ConnDOT's Bridge Inspection Manual. The visual inspection may find signs of distress, distortions, latent defects, loss of section, or deterioration. All exposed surfaces of concrete should be tapped with a hammer to locate delaminations or other deficiencies. Special attention must be given to not damage the electric cables and equipment in the vaults during the hammer testing.

All observed deficiencies and deteriorations should be documented with the dimensions of the length, width, height, depth of loss, orientation and location relative to a fixed, easily identifiable point. Particular care shall be given to documenting any increase in quantity or size of deterioration which have changed since the last inspection.

Photographs shall be taken of all components of the vault and detailed photographs shall be taken of all deficient areas.

1 of 4

Revised 3/31/10

In some instances of deterioration additional non-destructive testing may be required to correctly determine the extent of the deficiency. A vault with known deficiencies and/or questionable conditions may require more frequent inspections.

To record the findings of each inspection, a prepared set of drawings will be provided to the inspecting engineer for delineating any and all deficiencies. These drawings will become part of the inspection report. The structural integrity inspection may occur concurrently with the utilities' periodic inspection of their electric facilities.

EXHIBIT A

LIST OF VAULTS IN CONNDOT ROADWAYS
SUBJECT TO STRUCTURAL INTEGRITY INSPECTION PROGRAM

MIDDLETOWN-NORWALK PROJECT (CSC Docket # 272)
25 Vaults

Vault #s	Location	Municipality
4901, 5801	Housatonic River boat ramp near I-95	Milford
6407, 7507	159 Westport Avenue (US 1)	Norwalk
6416, 7516	245 Post Road East (US 1)	Westport
6421, 7521	1050 Post Road East (US 1)	Westport
6422, 7522	1200 Post Road East (US 1)	Westport
6431, 7531	2269 Post Road (US 1)	Fairfield
6432, 7532	1949 Post Road (US 1)	Fairfield
6433, 7533	1643 Post Road (US 1)	Fairfield
6435, 7535	1055 Post Road (US 1)	Fairfield
6438, 7538	122 Post Road (RTE 130)	Fairfield
6440, 7540	Fairfield Avenue (RTE 130) & Gilman Street	Bridgeport
6441	2704 Fairfield Avenue (RTE 130)	Bridgeport
6443, 7543	2098 Fairfield Avenue (RTE 130)	Bridgeport

GLENBROOK PROJECT (CSC Docket # 292)
29 Vaults

Vault #s	Location	Municipality
4000, 6200	MNRR Property on Hamilton Avenue	Stamford
4004, 5004, 6204	Darien Service Area	Darien
4005, 5005, 6205	Darien Service Area	Darien
4007, 5007, 6207	MNRR Noroton Heights Parking Lot	Darien
4013, 5013, 6213	MNRR Mechanics Street Parking Lot	Darien
4015, 5015, 6215	455 Post Road (US 1)	Darien
4017, 5017, 6217	54 Post Road (US 1)	Darien
4022, 5022, 6222	247 Post Road (US 1)	Norwalk
4023, 5023, 6223	147 Post Road (US 1)	Norwalk
4027, 5027, 6227	29 Van Buren Avenue (US 1)	Norwalk

3 of 4

Revised 3/31/10

EXHIBIT A

LIST OF VAULTS IN CONNDOT ROADWAYS
SUBJECT TO STRUCTURAL INTEGRITY INSPECTION PROGRAM

BETHEL-NORWALK PROJECT (CSC Docket # 217)
26 Vaults

Vault #	Location	Municipality
2511	Putnam Park Road (RTE 58) 1820' south of Dodgington Road (RTE 302)	Bethel
2512	Putnam Park Road (RTE 58) 1860' south of Dodgington Road (RTE 302)	Bethel
2519	Redding Road (RTE 107) 540' south of Peaceable Street	Redding
2520	Redding Road (RTE 107) 820' north of Meadow Ridge	Redding
2523	RTE 7 3460' south of RTE 107	Redding
2301	RTE 7 680' south of Wilton Acres	Wilton
2302	RTE 7 290' south of Hollyhock Lane	Wilton
2303	RTE 7 830' south of Kensett Avenue	Wilton
2304	RTE 7 410' south of Heathcote Road	Norwalk
2305	RTE 7 (Main Avenue) north of Grist Mill Road	Norwalk
2306	RTE 7 (Main Avenue) 600' north of Valley View Road	Norwalk
2307	RTE 7 (Main Avenue) 810' north of O'Donnell Road	Norwalk
2308	RTE 7 (Main Avenue) at Merritt Parkway (east) exit ramp	Norwalk
2309	RTE 7 (Main Avenue) 200' north of Linden Street	Norwalk
2310	RTE 7 (Main Avenue) 350' north of Broad Street	Norwalk
2002	Putnam Park Road (RTE 58) 1100' south of Hoyts Hill Road	Bethel
2003	Putnam Park Road (RTE 58) 2820' south of Hoyts Hill Road	Bethel
2004	Putnam Park Road (RTE 58) 420' north of Sunset Hill Road	Bethel
2005	Putnam Park Road (RTE 58) 3000' south of Sunset Hill Road	Bethel
2006	Putnam Park Road (RTE 58) 4650' south of Sunset Hill Road	Bethel
2007	Putnam Park Road (RTE 58) 1600' north of Putnam Park entrance	Redding
2009	RTE 107 1730' south of Putnam Park entrance	Redding
2010	RTE 107 700' south of Musket Lane	Redding
2011	RTE 107 1000' south of Lonetown Road	Redding
2012	RTE 107 at John Reed Road	Redding
2013	RTE 107 1970' south of John Reed Road	Redding

4 of 4

Revised 3/31/10

WMS 82.01-234 Manhole Inspections & Upgrades

This document outlines the implementation of a standard operating procedure for company personnel entering a manhole.

1.0 Introduction

1.1 Manhole inspections help ensure the structural and electrical integrity of the Eversource system.

1.1.1 Inspection results are used to proactively repair and/or upgrade the system.

1.2 Manhole inspections are to be performed on various system manholes including, but not limited to:

1.2.1 Distribution Manholes

1.2.2 Transmission Manholes

1.2.3 Network Manholes

1.2.4 Pipe-type Cable System Manholes

2.0 Reference Documents

ESOP 100 Switching and Tagging

EMP 5.59 Underground Vaults and Manholes

OP-5042 Pipe-Type Cable Manhole Inspection Form

TD 955 Confined Space Requirements

WMS 88.11-234 Substation Work Area Identification

WMS 81.13-234 Underground Thermography of Cables & Cable Accessories in Manholes & Vaults

WMS 90.01-3 Method for Checking Stray Voltage Sources

3.0 Definitions

3.1 Manhole – A subsurface enclosed space with an entry cover that personnel may enter and that is used for installing, operating, and maintaining submersible equipment or UG cable.

3.2 Planned Entry – Any entry being made to a manhole for the purpose of performing scheduled maintenance on any piece of equipment located within the manhole. This includes, but is not limited to, routine maintenance, cable installation, and/or cable splicing.

3.3 Preventative Maintenance – Any entry being made to a manhole to perform Major Distribution Level Inspection or Major Transmission Level Inspection as specified in EMP 5.59.

3.4 Vault – An enclosed space with a door, above or below ground, that personnel may enter and that is used for installing, operating, or maintaining equipment or cable.

4.0 General

4.1 This document covers types of inspections to be performed on manholes depending on type of work along with the associated inspection forms.

4.1.1 Inspection forms shall be completed for each entry. Digital forms may be used to complete the inspections, otherwise paper (hardcopy) forms shall be completed.

.1.1. All the form information MUST be completed before the inspection is considered complete.

4.2 During unplanned work including unplanned power restoration, leak-locating, or fault-locating activities, all requirements outlined in Safety and Pre-Entry Inspection section of this document shall be completed by qualified employees prior to entry.

4.2.1 Inspection forms are not required for these unplanned work manhole entries.

4.3 Minor repairs identified during inspection may be completed immediately. Repairs requiring more extensive work are noted on the inspection form.

4.3.1 Follow up preventative and corrective maintenance can be scheduled for a later date

4.4 Manholes will be cleaned as required based on inspection results.

4.4.1 Any manholes shall be cleaned more frequently based on their history or maintenance requirements.

5.0 Safety and Pre-Entry Inspection

5.1 This inspection shall be completed regardless of reason for entry and prior to entering a manhole.

5.2 Complete all entry and rescue requirements as stated in TD 955.

5.3 Indicate if known or suspected asbestos-containing materials are present in the manhole.

5.3.1 If known or suspected asbestos-containing materials (ACM) are present and will be impacted by work in the manhole; contact the Sustainability & Environmental Affairs Department Asbestos Program Coordinator or an approved Asbestos Abatement Contractor to abate the material(s). All known or suspected ACM must be disturbed only by a licensed asbestos abatement contractor.

5.3.2 For planned work, the Sustainability & Environmental Affairs Department Asbestos Program Coordinator can provide sampling services to determine whether suspect materials contain asbestos.

5.3.3 If asbestos-containing materials (ACM) is in good condition and will not be impacted by work, it can remain in place.

5.4 Prior to removing the manhole cover, test the cover and casting for stray voltage using a voltage sensor per **WMS 90.01-3**.

5.4.1 If voltage is detected, contact your Supervisor or Dispatch immediately for corrective action.

5.4.2 Record the measured voltage, even if it is zero, on the Manhole Inspection Form.

5.5 Inspect the cover and casting for damage, signs of vandalism, and verify that they can be removed properly.

5.5.1 Document the manhole cover type and if the cover needs to be replaced.

5.5.2 After removing the cover inspect the reverse side of the cover for damage.

5.6 Inspect the manhole tag.

5.6.1 Document the presence and condition of the manhole tag and replace if necessary.

5.7 Inspect the ladder for structural integrity and verify that it is in satisfactory condition, when applicable.

5.7.1 Verify all ladders are set up properly and grounded to system.

5.7.2 From outside the manhole, inspect for signs of water and if pumping is required.

CAUTION: Notify your Supervisor and the System Control Center immediately of any dangerous conditions, observed or measured, that do not meet the criteria outlined in the manhole entry standard, **TD 955**.

6.0 Planned Entry / Non-Targeted Inspection

6.1 This inspection shall be completed for any entry being made to a manhole for the purpose of performing scheduled maintenance on any piece of equipment located within the manhole.

6.2 Complete the Safety and Pre-Entry Inspection section of this standard, including all entry and rescue requirements as stated in **TD 955**.

6.3 Perform infrared (IR) thermography scan per **WMS 81.13-234** which refers to non-targeted, trouble work, or a safety inspection for a quick sweep and visual analysis of the location.

6.4 Complete Manhole Inspection Form per Manhole Inspection Form Details section of this document.

7.0 Preventative Maintenance / Targeted Inspection

7.1 This inspection and associated form shall be completed per schedule requirements outlined in **EMP 5.59**.

7.2 Complete the Safety and Pre-Entry Inspection section of this standard.

7.3 Complete the Structural Integrity Inspection section of this standard.

7.4 Perform entire infrared (IR) thermography process per **WMS 81.13-234** to check for heat abnormalities on primary connections, secondary connections, and accessories, as applicable.

7.5 Complete Manhole Inspection Form per Manhole Inspection Form Details section of this document.

8.0 Manhole Inspection Form Details

8.1 Indicate the following on the inspection form:

8.1.1 Presence of Limiters.

8.1.2 The presence of 4kV oil switches and if they have been retrofitted.

8.1.3 The number and cable size of network mains.

8.1.4 Presence of RTU enclosures and antenna.

8.1.5 Presence of PILC Cable.

8.2 Inspect, repair (when possible) and document the following:

8.2.1 Limiters – If replacement is needed indicate limiter size.

.1.1. Use clamp-on ammeter to verify current in each phase of each conductor.

8.2.2 Fault Indicators – Check condition, clean, and replace if necessary.

8.2.3 Equipment Status Indicators – Check condition, clean, and replace if necessary.

8.2.4 Hangers – Replace broken hangers required to properly support cables.
.4.1. Replace broken or damaged plastic inserts to properly support cables.

8.2.5 Stanchions – Check to see if stanchions are pulling away from manhole walls or if they are rusted or broken.

8.2.6 Fairleaders/Duct Shields – Required for all ducts that enter manhole and contain cables. Install or replace where required.

8.2.7 Arc proofing – Required for entire length of distribution cable contained within manhole (not used on asbestos insulated or low voltage cables). Install or replace where required.

8.2.8 Coating – Repair damaged pipe type surface coating on pipe type cable systems.

8.2.9 Bond frame – Check condition and replace with new, if required

8.2.10 Bonding – Verify all distribution cables and equipment (e.g., transformers, switches, etc.) contained within manhole are properly bonded to bond frame.

8.2.11 Primary and Secondary Cables – Inspect all cables in the manhole for signs of damage such as:

11.1. Missing insulation

11.2. Melted insulation.

11.3. Burn marks.

11.4. Insulation swelling

11.5. Exterior lead sheath cracking on or around cable bends.

11.6. Damage to pipe surface coating

11.7. Verify that the cable(s) contained within the manhole are properly labeled.

8.2.12 Primary and Secondary Joints – Inspect for signs of damage such as:

12.1. Missing insulation

12.2. Melted insulation.

12.3. Burn marks.

12.4. Insulation swelling

12.5. Arc proofing, duct to duct.

12.6. Leaking high voltage compound

12.7. Leaking cable insulation oil

12.8. Cracked wipes.

12.9. Abnormalities in sleeve shape

12.10. Holes in lead sleeve

12.11. Improperly attached bond wire to lead sleeve.

8.2.13 Fiberoptic Cable – Visually inspect cable for signs of damage and confirm that it is racked and secure.

.13.1. If damaged fiber optic cables are found, contact the System Desk Supervisor.

8.2.14 Re-racking – Perform minor re-racking, if required.

8.2.15 Transformer – Inspect for oil leaks and/or defects, and/or overloaded condition.

NOTE: If dielectric fluid/oil is identified, contact your Supervisor, and refer to applicable work procedures related to any required water management prior to entry. Should the oil be a release from electrical equipment (including cables), notify SOC/Dispatch who will notify the

on-call environmental coordinator to coordinate any required additional assessment and cleanup actions.

8.2.16 Switches – Inspect for oil leaks, defects, and/or overloaded condition.

16.1. Verify the switch(es) contained within the manhole are properly labeled.

16.2. Ensure oil switches, VFI switches and load Break switches are identified and inspected.

8.2.17 Sumps & Drains – If present, check to ensure

17.1. Signs of excessive water entering the facility are noted and that the presence of any water sheen, unusual odor, water discoloration, or any significant sludge buildup is noted.

17.2. Drains are not blocked.

17.3. Drains have a functional trap.

17.4. Gravity sumps are clean.

17.5. Sump pumps, if present, are working and installed properly.

17.6. Proper operation of installed the oil-water separator if present.

8.2.18 Other – Any other component or abnormal condition observed in manhole that is not listed above.

8.3 Perform secondary sheath voltage testing as follows:

8.3.1 Insert a 3,000 Ohm (Fluke SV225 Stray Voltage Eliminator or other manufacturer equivalent) into the voltmeter probe ports.

8.3.2 Insert the test leads into the stray voltage eliminator.

8.3.3 Attach one meter lead to ground on the manhole ground system.

8.3.4 Attach the second lead to the secondary sheath surfaces and test for any leakage (secondary mains, services, bus bars, and molded crabs - both limited and nonlimited).

8.3.5 Verify that voltage values between the manhole system ground and sheath/equipment sample points are less than 40 volts.

8.4 Complete Structural Integrity Inspection section of this document.

8.5 Additional repair work should be noted on the digital or hardcopy of the Manhole Inspection Form.

8.5.1 If hardcopy form is used, forward the completed Manhole Inspection Form to the appropriate Supervisor for review.

8.5.2 Digital forms will automatically update Maximo record data and open additional work orders if necessary.

9.0 Structural Integrity Inspection

9.1 This inspection focuses on the structural components of the manhole and shall be completed on manhole inspection form.

9.2 Inspect the walls and ceiling; frames and covers for any signs of:

9.2.1 Excessive cracking or flaking concrete.

9.2.2 Exposed or corroded reinforcing steel.

9.2.3 Severely rusted I-beams

9.2.4 Severely pitted or rusty structural components, etc.

9.2.5 Signs of bowing out

9.2.6 Corrosion and spalling on horizontal and vertical concrete beams.

9.2.7 Fatigue on the bottom steel beam flanges

9.3 Inspect Beam Pockets to ensure:

9.3.1 Sufficient bearing surface

9.3.2 Beams lay flat in the pocket, with no torsion.

9.3.3 Shims, concrete, and bearing surfaces are in good condition.

9.3.4 Beams have proper embedment into the pocket.

9.4 Inspect the manhole for excessive mid-span deflection of:

9.4.1 Walls

9.4.2 Floors

9.4.3 Lids

9.4.4 Supports

9.5 Check pulling eyes for corrosion and condition of hardware.

9.6 Specify a Structural Integrity Classification (C1, C2, C3, C4) in the comments section of inspection form (paper or digital) based on the visual inspection of these items.

9.6.1 Class 1 (C1) – A Structural Engineer will recommend recommended repair, replacement, and/or re-inspection schedule as soon as possible, not to exceed one year. Manhole requires repairs within one year's time.

9.6.2 Class 2 (C2) – Deterioration Noted. This manhole exhibits structural degradation that is not likely to cause failure within the next year. Review within one year by Structural Engineer to determine recommended repair, replacement, and/or re-inspection schedule.

9.6.3 Class 3 (C3) – Manhole exhibits structural degradation, but failure is not likely within the next five years. This structure should be reviewed by a Structural Engineer to recommend recommended repair, replacement, and/or re-inspection schedule.

9.6.4 Class 4 (C4) – Re-inspect at the next planned entry.

10.0 Pipe-Type Cable System Manhole Inspection

10.1 Complete the Pre-Entry Inspection section of this standard.
10.2 Complete the Structural Integrity Inspection section of this standard.

10.3 Perform infrared (IR) thermography inspection per **WMS 81.13-234** to check for heat anomalies on primary connections, secondary connections, and accessories, as applicable.

10.4 Inspect, repair (when possible) and document the following:

10.4.1 Coating – Inspect and repair damaged pipe type surface coating.

10.4.2 Bonding - Verify all distribution cables and equipment (e.g., joints, pipe) contained are properly bonded, as required.

10.4.3 Primary Cables - Verify the Pipe Type Cable(s) are properly labeled.

10.4.4 Inspect all pipes, valves and structures contained within the manhole for obvious signs of damage and the following:

4.1. Dielectric fluid present in Manhole
4.2. Dimension and Clearance
4.3. Damage to pipe surface coating
4.4. Condition of Thermal Conductor Leads
4.5. All Valves wrapped and labeled properly.
4.6. Condition of Electrolysis Test Leads

10.4.5 Pipe Surface Coatings - Inspect pipe-type cable surfaces in manhole for obvious signs of damage, examples of damage noted above.

NOTE: Manholes listed in the CTDOT Structural Vault Inspection Letter shall be conducted hammer testing.

10.4.6 Fiberoptic Cable – Visually inspect cable for signs of damage and confirm that it is racked and secure.

.6.1. If damaged fiber optic cables are found, contact the System Desk Supervisor.

10.4.7 Other - Any other component or abnormal condition observed in manhole that is not listed above.

10.5 Additional repair work should be noted on the digital or hardcopy inspection form.

10.5.1 A maintenance work order will be generated for the repairs to be completed.

10.6 If hardcopy form is used, forward the completed Pipe-Type Manhole Inspection Form to the appropriate Supervisor for review.

10.6.1 Digital forms will automatically update Maximo record data and open additional work orders if necessary.

11.0 Exiting Underground Locations

11.1 Upon completion of work and/or routine scheduled maintenance within a manhole:

11.1.1 If there are communication lines within manhole that are creating a hazard, verify Eversource Communications team has been alerted to contact responsible party.

11.2 After exiting the manhole, test the manhole cover and casting for stray voltage.

12.0 Follow-Up Preventative Maintenance

12.1 When the digital form is deemed completed, the form is automatically saved within the form software program.

12.1.1 When the digital form indicates findings/issues of inspection items, follow-up work requests will automatically generate in Maximo.

.1.1a. Approved Work Requests will automatically create a new follow-up Work Order.
.1.1b. Canceled Work Requests will remove it from queue and no further action required.

12.1.2 When the digital form indicates no findings/issues, then the form is automatically uploaded and saved to Maximo.

.2.1. No further action required.

12.1.3 Based on structural integrity classification, follow-up work from civil or structural engineer may be required.

Appendix A –Manhole Inspection Form

EVERSOURCE

DISTRIBUTION OR NETWORK MANHOLE INSPECTION

Region: CT EMA WMA NH

Reviewed By:	**ID #**	**Date:**
Signature	**Follow-up Work Required?**	◯ Yes ◯ No

Inspection W.O. #	Task	Project	Description

***Prior to the start of the inspection, review the details defined in Work Method Standard WMS 82.01.*

General Information:

Manhole #: _____ Start Date/Time: _____
Inspected By: _____ End Date/Time: _____
Employee ID#: _____ Cross Street: _____
Address: _____ City/Town: _____
# of AC Network Mains: _____ Cable Size: _____

Line Numbers	From Station	To Station	Latitude	Longitude

Pre-Entry

	Inspection	Circle One	
*1	Stray / Contact Voltage Present?	Yes	No
*2	Is gas present in Manhole? (Test per entry procedure)	Yes	No
3	Is known or suspected asbestos present in mannhole?	Yes	No
*4	Condition of Manhole casting satisfactory?	Yes	No
*5	Condition of Manhole cover satisfactory?	Yes	No
*5a	Is the cover seated?	Yes	No
*5b	Is the cover rocking? *If yes, specify why in the comments (dirt, damage, etc.).*	Yes	No
*6	Condition of Manhole Chimney/Structure Satisfactory?	Yes	No
*6a	Exposed Rebar?	Yes	No
*6b	Rebar Corrosion Present?	Yes	No
*7	Manhole Cover Type	Vented	Solid
*8	Condition of manhole Tag satisfactory?	Yes	No
*9	Condition of ladder satisfactory?	Yes	No
*10	Is Pumping Required? *If Yes, list the approximate amount in the comments.*	Yes	No
*11	Is Dielectric Fluid/Oil Present in the Manhole? *If Yes, list how the fluid is to be abated in the comments. Follow instructions in Sec 6.5.16 of WMS 82.01*	Yes	No

Items marked with an asterisk (*) are to be inspected whenever entering a manhole.

When an abnormal conditions is found detail the condition in the comment section; include the line item and the reason.

	Inspection	Work Completed Quantity	Satisfactory	Onsite Repairs Completed	Un-satisfactory	Not Applicable
12	Manhole's walls, floor, ceiling, etc.		S	R	U	N/A
13	Infrared Inspection per WMS 81.13		S	R	U	N/A

FORM # OP #### Page 1/2 Rev 28 Sept 22

EXAMPLE

EVERSOURCE

DISTRIBUTION OR NETWORK MANHOLE INSPECTION

Region: CT EMA WMA NH

Inspection Continued

		Work Completed Quantity	Satisfactory	Onsite Repairs Completed	Un-satisfactory	Not Applicable
14	Limiters Size:_____		S	R	U	N/A
15	Fault Indicators		S	R	U	N/A
16	Equipment Status Indicators		S	R	U	N/A
17	Hangers & Inserts		S	R	U	N/A
18	Stanchions		S	R	U	N/A
19	Fairleaders		S	R	U	N/A
20	Duct shields		S	R	U	N/A
21	Arc-proofing		S	R	U	N/A
22	Coating		S	R	U	N/A
23	Bond frame		S	R	U	N/A
24	Bonding Size:_____		S	R	U	N/A
25	Primary & Secondary Cables Size:_____		S	R	U	N/A
26	Primary & Secondary Joints		S	R	U	N/A
27	Fiberoptic Cable		S	R	U	N/A
28	Re-racking		S	R	U	N/A
29	Transformer Size:_____		S	R	U	N/A
30	Switches (VFI, load break, etc.)		S	R	U	N/A
30a	4 kV oil switches present & retrofitted?	Not Present		Present	Retrofitted	
31	Sumps & Drains		S	R	U	N/A
32	RTU Enclosure and Antenna		S	R	U	N/A
33	Other (note in comments)		S	R	U	N/A
34	Secondary Sheath Voltage Testing		S	R	U	N/A

When an abnormal conditions is found detail the condition in the comment section; include the line item and the reason.

Exiting

35	Manhole Left Clean?	Yes	No
36	Manhole Cover Secured?	Yes	No
37	Follow up work required?	Yes	No

List Issues Found, Repairs Made or Any Additional Comments

FORM # OP-#### Page 2/2 Rev 28-Sept-22

EXAMPLE

EVERSOURCE

PIPE-TYPE CABLE (PTC)
MANHOLE INSPECTION

MH No.: _____

Reviewed By: _____	**ID #** _____	**Date:** _____
Signature _____	**Follow-up Work Required?**	◯ Yes ◯ No

Inspection W.O. #	Task	Project	Description

***Prior to the start of the inspection, review the details defined in Work Method Standard W1001.*

General Information:

Manhole #: _____ Start Date: _____
Inspected By: _____ Start Time: _____
Employee ID#: _____ End Date: _____
Address: _____ End Time: _____
Cross Street: _____ City/Town: _____

Line Numbers	From Station	To Station	Latitude	Longitude

Pre-Entry

	Inspection	Circle One			
		Manhole 1		Manhole 2	
*1	Stray / Contact Voltage Present?	Yes	No	Yes	No
*2	Condition of Manhole casting satisfactory?	Yes	No	Yes	No
*3	Condition of Manhole cover satisfactory?	Yes	No	Yes	No
*3a	Is the cover seated?	Yes	No	Yes	No
*3b	Is the cover rocking? *If yes, specify why in the comments (dirt, damage, etc.).*	Yes	No	Yes	No
*4	Condition of Manhole Chimney/Structure Satisfactory?	Yes	No	Yes	No
*4a	Exposed Rebar?	Yes	No	Yes	No
*4b	Rebar Corrosion Present?	Yes	No	Yes	No
*5	Condition of manhole Tag satisfactory?	Yes	No	Yes	No
*6	Is Pumping Required? *If Yes, list the approximate amount in the comments.*	Yes		No	
*7	Is Dielectric Fluid/Oil Present in the Manhole? *If Yes, list how the fluid is to be abated in the comments. Follow instructions in Section 6.516 of WMS 82.01*	Yes		No	
8	Is known or suspected asbestos present in the Manhole?	Yes		No	

Items marked with an asterisk (*) are to be inspected whenever entering a manhole.

When an abnormal conditions is found detail the condition in the comment section; include the line item and the reason.

Inspection

9	Condition of the manhole's walls, floor, ceiling, etc. satisfactory?	Yes	No
10	Specify material of sleeved entrance for line pipes.	Steel	PVC

FORM # OP-5042 Page 1/2 Rev 13-Apr-22

EXAMPLE

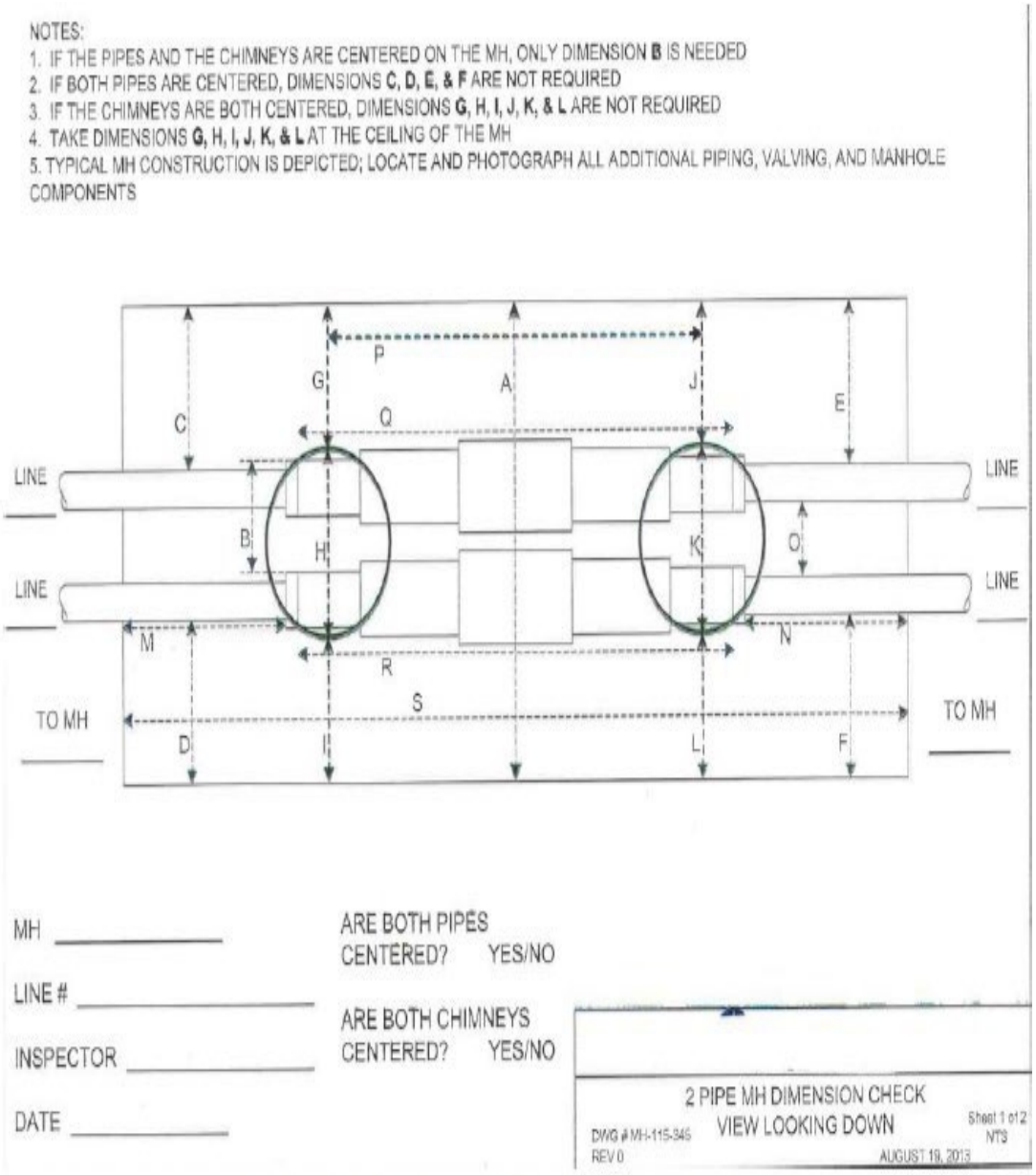
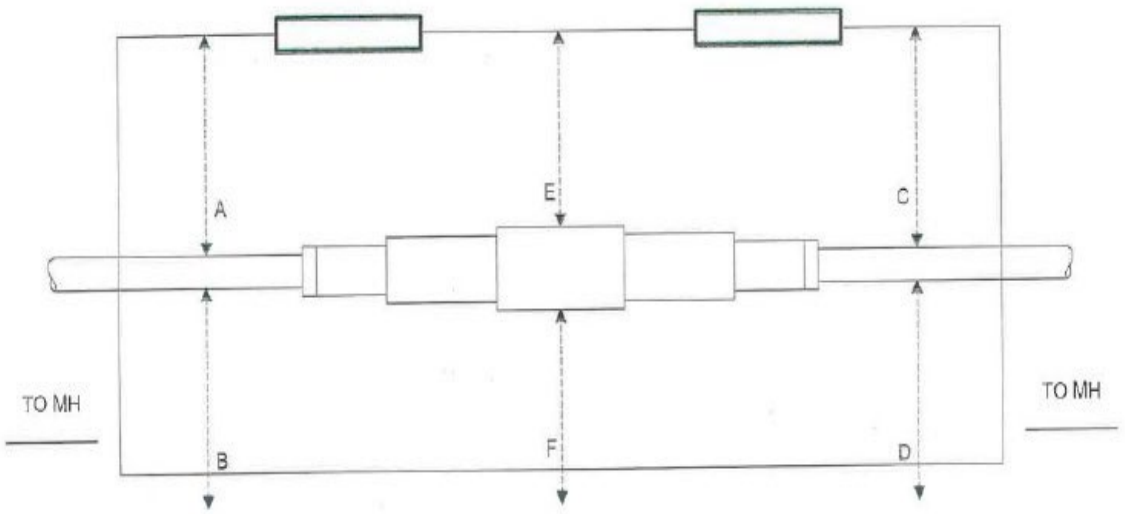


Figure C1 – Two Pipe-Type Cable Manhole Dimension Top View

NOTES:
1. LOCATE VALVES – VENT (TOP OF SPLICE) & DRAIN (BOTTOM OF SPLICE)
2. TYPICAL MH CONSTRUCTION IS DEPICTED; LOCATE AND PHOTOGRAPH ALL ADDITIONAL PIPING, VALVING, AND MANHOLE COMPONENTS



MH _____

LINE # _____

INSPECTOR _____

DATE _____

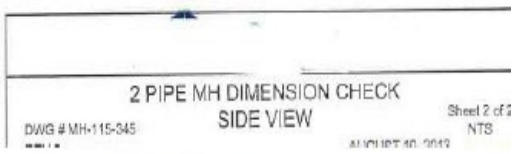


Figure C2 – Two Pipe-Type Cable Manhole Dimension Side View

Appendix D – Inspection Item Photos and Examples

Manhole cover type: vented vs solid

Blast Proof Cover | Solid Cover | Vented Cover



Is pumping required?

Water on floor and cable not racked.



Oil leaking on wall and floor.



Corroded overhead beam II



Deteriorating Vault Ceiling II,



Rusted & Corroded beam II



Deteriorated beam from corrosion II,



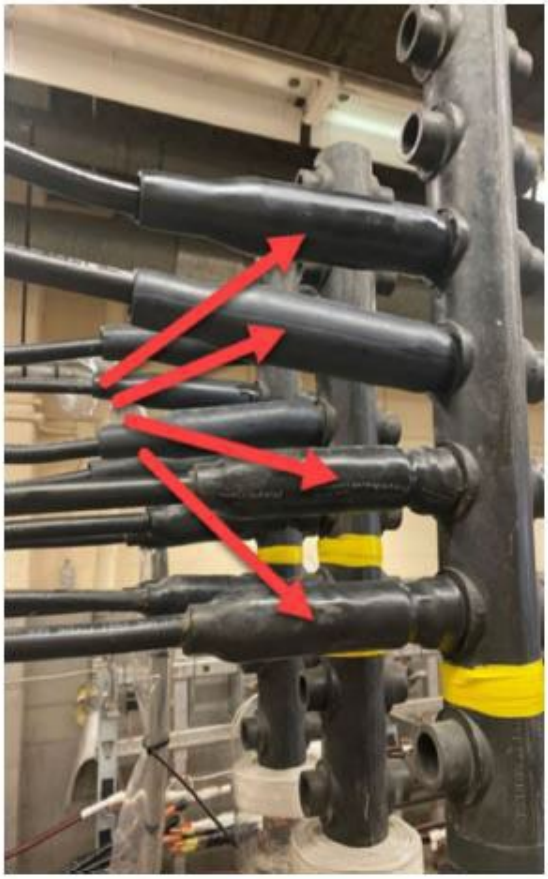
Examples of limiters ↓



A blown limiter does not contain a visual indicator. It must be tested. ↓



Limiters attached to a mole ↓



Fault Indicators

Fault Indicators ↓





Racked cable but secondary cables do not have rack insulator



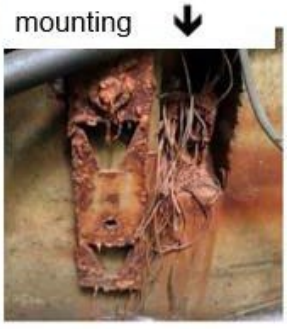
Cable arm (hanger) and support (stanchion)



Rusted/Oxidized cable arm



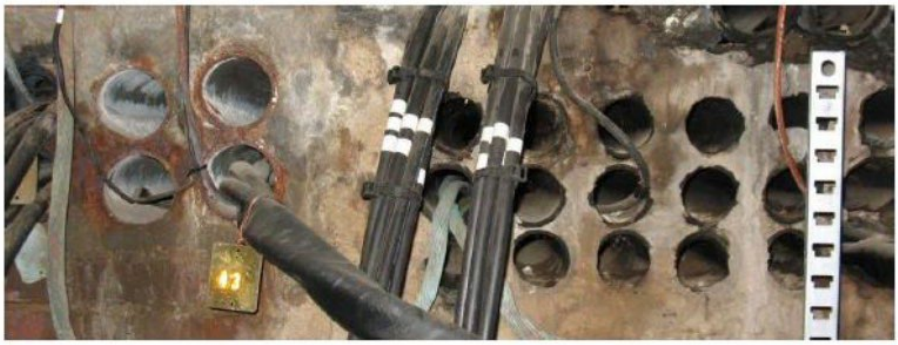
Rusted/Oxidized cable rack mounting



Duct Shields ↓



Duct shields missing ↓



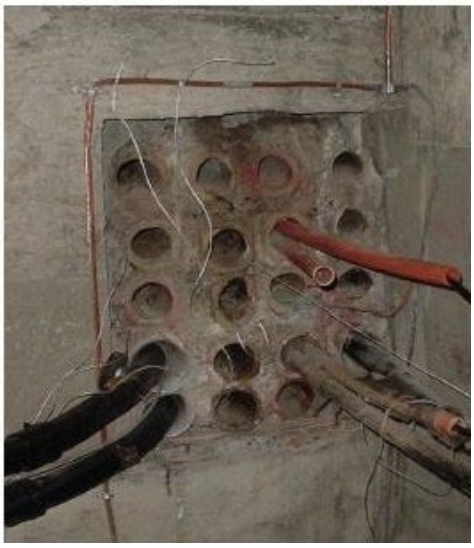
Arc-proofing

Arc proofing installed on cables "' Arc proofing tape. "'





Bond frame, **I**,, Ground bus**, I,,**

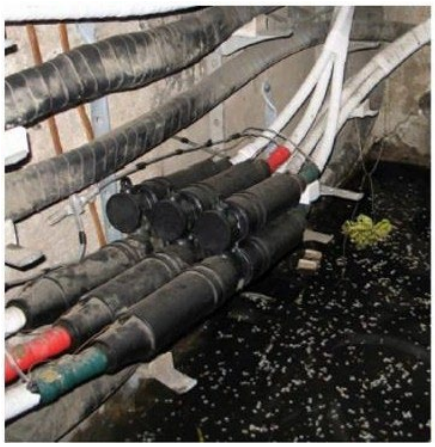




System ground**, I,,**



Disconnectable Splice for Primary Cable Ii,, Fusible crab joints for Secondary Cable Ii,,





Primary & Secondary Joints

Single joints, wrapped with arc proofing +



Disconnectable Splice for Primary Cable + Fusible crab joints for Secondary Cable +





The cable is not racked properly ↓



The cable has now been racked properly ↓



Transformer



← 100kva (smooth) and 167kva (fins) transformers

← Submersible transformers →



4 kV oil switches present & retrofitted?



Phoenix Oil Switch without the retro fitting



Phoenix Oil Switch with the retrofitting, I,

Oil Switches removed from service.





APPENDIX 18

APPENDIX NO LONGER USED

APPENDIX 19

INFRARED SURVEY PROGRAM

5.22 Infrared Surveys

1.0 Introduction

1.1 The Infrared (IR) Survey Program utilizes technology known as Thermography to identify degraded components. Thermography is a non-destructive test method that remotely senses and measures heat emitted from a component, allowing a temperature comparison between the component, and adjacent or contiguous materials. A significant rise in temperature on a specific component referred to as a “hot spot” or “finding”, indicates that the component is in a degraded condition. The magnitude of the temperature rise is in part proportional to the relative resistance of the device and is therefore an indicator of the severity of the degradation.

1.2 In classifying the severity of a finding, the thermographer must also consider a variety of factors that influence the measured temperature. Two attributes of the material of which the item being scanned is made, emissivity and reflectivity, impact the readings obtained with thermal imaging equipment. Whenever possible, comparisons should be made between components made of like material. The relative load on the circuit must be considered, since higher load will result in a higher temperature rise. In addition to the above, environmental conditions (e.g., direct sunlight, overcast, precipitation, ambient temperature, wind speed, etc.) must also be considered, as they relate to cooling being provided to the component.

1.3 The type of component is a factor in determining appropriate corrective actions. Passive, air-cooled components, such as hot-line clamps or splices, can typically tolerate higher temperatures before failure becomes imminent and are generally allowed more latitude in terms of response/repair time. Oil-filled or active devices, such as Capacitors or Vacuum Reclosers, cannot tolerate very high temperatures; corrective action must be taken at relatively low magnitudes of temperature rise for these components.

2.0 Reference Documents

EMP 5.78	Transmission Overhead
TD 853	Infrared Thermographic Inspections
WMS 6 .10-1	Substation Transformer Thermography

WMS 60.10-234	Substation Transformer Thermography
ASTM E 1934-99a	Standard Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography (2018)
NFPA 70B	Standard for Electrical Equipment Maintenance

3.0 Definitions

The abbreviations used for the intervals are:

3.1.1 Y = Year, i.e. 2Y = 2 Years

3.1.2 M = Month

3.1.3 A/R = As Require

4.1 Facilities/Equipment

4.1 An Infrared Survey is performed on all Distribution three-phase overhead backbone circuitry, Distribution substation equipment, and other equipment deemed necessary.

4.1.1 Three-Phase overhead circuitry for distribution backbone and transmission circuitry, which includes:

- Capacitors (Pole-top)
- Disconnects
- Lightning Arrestors Inspection
- Overhead Circuit
- Potential Transformers
- Reclosers
- Regulators (Pole-top)
- Transformers
- Sectionalizers and Switches
- Fuses

4.1.2 Substation equipment, which includes:

- Capacitors (Substation) (Vacuum)
- Capacitor Switches
- Circuit Switchers
- Disconnect Switches
- Lightning Arresters
- Load Tap Changers
- Oil Circuit Breakers Transformers
- Potential
- Regulators (Substation)
- Transformers

4.1.3 Other equipment (as deemed necessary), which includes:

- Air Circuit Breaker Switchgear
- Pad-Mounted
- SF6 Gas Circuit Breakers
- Underground Cables

- Underground Switches
- Transformers
- Underground
- Vacuum Circuit Breakers
- Other DB Equipment

4.2 Survey Findings

4.2.1 The findings are classified as "Minor," "Serious," and "Emergency" in increasing order of severity. Refer to TD 853 – Infrared Thermographic Inspections for details. This TD has been endorsed by all three operating companies.

5.0 Inspection and Maintenance Activity Schedules

Table 1 – Infrared Survey Maintenance Intervals

Infrared Survey Maintenance Schedule	Interval
Time-Directed	
Infrared Survey – Substation	6M
Infrared Survey – Three-Phase Distribution Overhead Backbone	1Y (Note 1)
Infrared Survey – Transmission, Overhead	See **EMP 5.78**
Condition-Based	
Perform follow-up based on analysis of IR surveys	A/R
Failure Finding	
Report Emergency level findings immediately to the appropriate AWC personnel	A/R

NOTE: 1. Infrared inspections of three-phase distribution OH backbone on right of ways is NOT performed unless other conditions identified during the routine visual inspection warrant further investigation.

2. Perform an equipment visual and mechanical inspection prior to performing an infrared survey when applicable.

6.0 Maintenance Categories

6.1 Condition Monitoring

6.1.1 Not Applicable

6.2 Time Directed

6.2.1 Routine Inspection

1.1. Perform infrared surveys on all Distribution overhead three-phase backbone,

Transmission overhead circuits and all substation equipment.

1.2. Analyze the findings of the surveys, prioritize the actions to be taken, and distributereports in accordance with **TD 853** - Infrared Thermographic Inspections.

1.3. If deemed necessary, an oil sample can be taken to confirm an abnormally high and unacceptable temperature.

1.4. Priority and response recommendations provided by the Thermographer are based solely on evaluated equipment condition and may be adjusted by maintenance management and/or work management personnel as necessary to accommodate scheduling concerns.

6.3 Condition Based

6.3.1 Actions Based on Findings:

.1.1. Infrared surveys may find temperatures that indicate minor to serious conditions that require action ranging from more frequent inspection to immediate repair or replacement of the component.

7.0 Infrared Inspection Maintenance Basis Documentation

7.1 The maintenance activities and their schedules are based on industry experience, feedback from the Infrared Test Specialists, and subject matter experts.

Table 3 – Infrared Inspection Maintenance Basis Documentation

Requirement	Basis
Infrared Survey – 1Y	Industry Best Practices show that an annual Infrared survey provides reliable, continuous service in a cost-efficient manner.
Condition-Based Maintenance	Perform follow-up actions as required based on the results of survey analysis.

APPENDIX 20

NO LONGER USED