Pacific Gas and Electric Company®

Electric Transmission Preventive Maintenance Manual TD-1001M

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Introduction

This manual covers preventive maintenance for overhead and underground electric transmission facilities. These facilities must be inspected and patrolled in accordance with the following sections of this manual:

1. General Inspection and Patrol Procedures
2. Inspections
3. Patrols
4. Infrared (IR) Inspection Procedures
5. Maintenance Procedures

The procedures outlined in this manual (Sections 1 through 5) have been established to ensure uniform and consistent required procedures for inspections, patrols, equipment testing, and condition assessment of electric transmission line facilities.

This standard also includes requirements for the prioritization, scheduling, managing and documentation of corrective actions identified on existing electric transmission facilities that affect safety and reliability. These requirements comply with PG&E standards and current industry practices.

In addition, Section 6 provides specific enhanced inspection and maintenance requirements unique to facilities serving Diablo Canyon and Morro Bay Power Plants.

This standard supports UO Policy 3-7, "Gas and Electric Operation, Maintenance, and Construction," Utility Standard TD-1001S, "Electric Transmission Line Inspection and Preventive Maintenance Program" and the requirements to comply with California Public Utilities Commission (CPUC) General Order (G.O.) 165 "Inspection Requirements for Electric Distribution and Transmission Facilities", as well as relevant portions of G.O. 95 "Rules for Overhead Electric Line Construction" and G.O. 128 "Rules for Construction of Underground Electric Supply and Communication Systems". The requirements described in this document reduce the potential for component failures and facilitate a proactive approach to repairing or replacing abnormal components. This standard does not necessarily identify nonconformance to PG&E standards.

This standard is to be reviewed annually for updates, changes, errors, or omissions. When it is updated, the Filed Maintenance Practice (FMP) with the California Independent System Operator (CAISO) must also be reviewed and revised, as necessary. Significant changes in the frequency or scope of patrols and inspections may also trigger a review with the CPUC.

For the acronyms and definition of terms used in this manual, see 8.Appendix A: Acronyms and Definition of Terms.

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1. General Inspection and Patrol Procedures

1.1 Record Keeping

This section provides general records guidance and retention requirements for the maps, logs, and notifications used to document the inspections, patrols abnormalities and corrective actions identified on the electric transmission line system.

1.1.1 General Guidelines for Company Records and Documentation

Records must be stored electronically, unless impractical. REFER to Section 7 of the GOV-7101S Enterprise Records and Information Management Standard.

1.1.1.1 Electronic Records and Signatures

Transmission line has begun implementing electronic processes for activities such as notification creation. A mobile computer is utilized with the ET AI App to create notifications. To ensure proper documentation, both the traditional wet signature and an electronic signature will be acceptable forms of certifying compliance documents or to satisfy signature or verification purposes. Note that electronic signatures or verifications must come from a valid user logged onto a PG&E certified account (such as any account associated with PG&E single sign-on or SAP).

1.1.1.2 Hand-Written Records

Although use of electronic signatures and certifications are now allowed, the requirements for hand-written records have not changed.

All hand-written records must be completed using non-erasable ink. To correct an item on a hand-written record, the following requirements must be met:

- Use a non-erasable black or blue ink pen.
- Do not erase or white out any portion of the log.
- Draw a single line through the entry(s) being deleted.
- Enter the correct information into the log.
- Initial and date the change.

To ensure legibility, personnel must print their full name, initials, or LAN ID, as required, on these documents. Rubber stamps are not allowed to meet this requirement (Bulletin 247, Gas and Electric M&O Record Requirements, 12/31/07). All hand-written forms and paperwork requiring a qualified Company representative (QCR) or supervisor signature must be "wet" signed by hand in non-erasable blue or black ink by the respective personnel. Computer print outs with the date and LAN ID are acceptable; however, all signatures on paper must be "wet".

Routine, non-routine, and emergency circuit inspection or patrol reports generated by the QCR must be recorded in the appropriate SAP database, and the records maintained in accordance with the Independent System Operator (ISO) Transmission Control Agreements (TCA). Use ETPM Forms TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet - Typical", TD-1001M-F06, "Monthly Pipe-Type Routine Inspection - Typical", TD-1001M-F07, "Detailed Pipe-Type Inspection Sheet – Typical", TD-1001M-F08 "Quarterly XLPE Routine Inspection – Typical", TD-1001M-F09 "Detailed XLPE Manhole Inspection – Typical", TD-1001M-F10 "Alarms/SCADA Annual Test Sheet – Typical" and TD-1001M-F11 "Electric Pumping Plant Annual Calibration Sheet – Typical" to document abnormal conditions identified by the QCR during inspection and patrol.

These documents must identify that all structures and facilities were inspected or patrolled, and that all abnormal conditions observed were corrected or captured as maintenance notifications during the inspection or patrol.

In general, additional notes and comments should not be added to forms unless they further describe the findings captured. Acceptable notes for patrol and inspection field documentation includes:

- Access notes describing the navigation path or procedure used to safely and efficiently access the target structure or equipment
- Range finder readings describing the target span, temperature, date, time, and laser range finder (or similar) result
- Status of non-findings being monitored such as woodpecker hole position and size; ground movement near the structure; species presence.

1.1.2 Records Retention Requirements

Note: A legal hold supersedes all record retention requirements listed in this section. Do not destroy any records designated as part of a legal hold no matter how old those records are. All Electric Operations records are still under a legal hold as of publishing of this ETPM.

REFER to Section 9 of the GOV-7101S Enterprise Records and Information Management Standard for more information on legal holds.

Overhead and underground transmission line inspection and maintenance records must be maintained in accordance with CPUC General Order (G.O.) 165. Records may be in paper and/or electronic form and must be kept for 10 years, with the exception of climbing inspections on the 500 kV system, which must be maintained for 14 years.

When completed, inspection datasheets and forms must be kept in files by circuit name at the responsible transmission line maintenance supervisor's headquarters. The clerk will scan the datasheet and attach it to the patrol in SAP. Refer to Appendix E: Line Patrol File Guidelines for requirements on how to complete the forms and how to store the files. Annually for each circuit, two folders should be created. There will be one folder for Annual Patrols and one folder for the Line Files. Print the appropriate forms and include in the specific folder for each circuit. The following are typical management reports and records used to track required inspection and maintenance work. When applicable, these documents should be included in the respective circuit files at the transmission line maintenance supervisor's headquarters/central filing office.

- Underground Transmission Line Inspection Sheets
- Overhead Transmission Line Datasheets
- Completed Notification forms within SAP for maintenance work performed by transmission employees
- Object lists
- Notification forms submitted to other support groups that will be performing the maintenance, such as area maintenance and construction (M&C) employees, contractors, vegetation management (VM) personnel, pole asset management (PAM) personnel, etc.
- Completion notices in SAP for work performed by transmission employees
- Completion notices for work performed by others
- Poles Inspection Test Reports

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1.2 Purpose of Inspection and Patrol Activities

Inspection and patrol procedures are a key element of the preventive maintenance program. The actions recommended in this manual reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified, abnormal components.

Inspections include detailed visual observations of individual components, structures and equipment; operational readings; and component testing (i.e., hammer test, etc.) to identify abnormalities or circumstances that will negatively impact safety, reliability, or asset life.

Patrols include visual observations to identify abnormalities (i.e., obvious structural problems or hazards) or circumstances that will negatively impact safety.

Electric transmission line maintenance organizations may establish additional inspection, patrol, testing, and/or preventive maintenance requirements that exceed the requirements in this manual, based on area experience and local conditions, and as needed for special equipment unique to the area. Additionally, the Asset Management organization may require electric transmission line maintenance organizations to undertake unique, non-routine patrols and inspections as dictated by asset performance or other external factors.

1.2.1 Problem Identification

PG&E performs periodic inspections, patrols, and maintenance on its overhead and underground transmission facilities. Identify abnormal or potentially hazardous conditions by any of the following means:

- Periodic inspections or patrols of facilities in accordance with existing standards.
- Condition-based and/or diagnostic testing and monitoring of facilities.
- Observation by any employee during other activities, such as normal job assignments and emergency patrols QCR must perform a field assessment).
- Corrective Action Program (CAP) issue
- Internal reviews.
- Customer or general public reports (a QCR must perform a field assessment).
- During emergency or storm activities.
- The QCR does **not** define the specific corrective action to be performed but makes recommendations.

1.3 Documenting Abnormalities and Nonconformance

1.3.1 Reporting Nonconformance with CPUC General Orders

Any nonconformance with G.O. 95, "Rules for Overhead Electric Line Construction," and G.O. 128, "Rules for Construction of Underground Electric Supply and Communication Systems," that impacts safety or reliability, or an abnormal condition caused by third-parties that negatively impacts Company facilities, must be documented on an SAP notification. Abnormal conditions caused by third-parties must be reported to Land Management.

1.3.2 Reporting Abnormalities in Manufacture

Abnormal conditions or failures that could be the result of a manufacturer or workmanship defect must be reported on a Form 62-0113, "Material Problem Report" (MPR), and submitted

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to supplier quality improvement personnel for follow-up action, as described in SCM-2106P-01, “Material Problem Report Procedure”.

IF material is sent to Applied Technology Services (ATS) personnel for testing, THEN include a form TD-1957P-01-F01, “Component Testing Information Sheet.” as described in Utility Procedure TD-1957P-01, “Electric Transmission Line Equipment Failure Analysis Procedure.” CAUTION: When collecting failed components, care should be taken to protect the failed surfaces by avoiding touching the failed sections. Even minimal contact with the failed surfaces can prevent an accurate failure analysis.

MPR’s are **not** to be used for material which has failed as a result of end-of-service life or because of normal wear.

1.3.3 Reporting Vegetation Nonconformance

Initiate an SAP notification if trees or brush are within the vegetation clearance distances or pose a potential threat to fall into a conductor.

In addition to initiating the notification, take the action required, as based on the voltage class and the vegetation-to-conductor clearance distance listed in Table 1. Vegetation Clearance Distance.

Table 1. Vegetation Clearance Distance

Voltage (kV)	Clearance Distance	Action Required
60/70*	4 feet or less	Call VPM (Veg Program Manager)/Forester
115*	10 feet or less	Call VPM/Forester
230	10 feet or less	Call GCC and VPM/Forester
500	15 feet or less	Call GCC and VPM/Forester

* If the line is NERC/CAISO critical (Spaulding – Summit 60kV, Drum-Summit #1 115kV and Drum-Summit #2 115kV), call the GCC and VPM/Forester as required for 230kV and 500kV lines.

For all NERC transmission lines, if a tree poses an **imminent threat** (e.g., the tree is uprooting and has the potential to fall into conductors), but not within the clearance distances shown in Table 1. Vegetation Clearance Distance, also perform the required action described in Table 1. Contact the VPM/ Forester directly. A voice mail is not considered notification for an imminent threat. The information must be given directly to a person. If the VPM/Forester is not available, contact the next person within VM. The VM department will verify the condition per Utility Procedure TD-7103P-05, “Transmission Vegetation Management Imminent Threat Procedure”. Provide the following information:

- Description of the vegetation condition
- Location, including the line name, nearest tower number and approximate distance to the tower
- Field conditions, including information on environmentally sensitive areas
- Location access

For all vegetation notifications and hazard conditions that are encroaching on the vegetation-to-conductor clearance distance listed in Table 1. Vegetation Clearance Distance, the SAP notification form must indicate the following information:

- Facility Code = Vegetation, Damage Code = Overgrown, Action Code = Remove
- Priority A = Emergency Unsafe Condition

The VM group manages all vegetation notifications and will verify the condition and confirm the clearance distance per Utility Procedure TD-7103P-09, "T&D Vegetation Management Hazard Notification". VM must notify the issuing department when the conditions have been corrected or resolved and ensure that the notification has been closed.

As part of the routine VM work, VM inspects 100% of overhead lines annually and performs work necessary to ensure that no vegetation encroaches on PG&E clearance distances (see Table 1. Vegetation Clearance Distance above). Clearance distances are based on regulatory clearance requirements plus a buffer and vary by voltage. VM also manages a transmission reliability program designed to improve reliability and reduce fire risk by clearing incompatible vegetation from the full width of the right-of-way. This work is planned annually in collaboration with T-Line Asset Strategy.

In addition, VM performs tower and pole clearing as part of their routine tree work, to allow for the inspections of tower and pole bases and footings and down guys. The pre-inspection and tree crew contractors will inspect the vegetation around the poles, towers and down guys while doing their patrols and inspections. If woody vegetation is in contact with the pole or tower, or significantly interferes with the inspection of the pole or tower base or footings, then the contractors will arrange for appropriate vegetation work. If woody vegetation is in contact with the guy wire, the contractors will determine if vegetation work will be required and arrange for any necessary work. See Utility Procedures TD-7103P-01, "Transmission Non-Orchard Routine Patrol Procedure" and TD-7103P-02, "Transmission Orchard Patrol Procedure (TOPP)".

1.3.4 Reporting Other Nonconformance with Distribution Facilities

When QCRs are performing patrols and inspections on facilities with distribution assets, a patrol of the distribution assets should also be performed. Examples of the type of issues that could be identified are:

- Damaged or broken poles
- Broken or decayed crossarms
- Broken insulators
- Damaged tie wire
- Vegetation issues
- Missing or broken bridging wire

If there is an immediate hazard and/or emergency, contact the transmission line maintenance supervisor and standby, if needed. If a structural problem or hazard is identified, that is NOT an emergency, note the issue on the List of the Datasheet. Submit a digital photo documenting the issue and the pole number. Contact the local PS&R Supervisor, leaving a voice mail message if not available, including the following information:

- Issue identified (e.g., broken crossarm)
- Transmission pole number (if distribution underbuild) or distribution pole number
- Confirm that a map will be emailed if there is no pole number.
- Latitude and longitude of the pole

The transmission line maintenance supervisor will review the finding while reviewing the patrol or inspection documents. The clerk will create an email outlining the above details to the local

PS&R Supervisor with a cc: to the QCR and the transmission line maintenance supervisor and attach the copy of the map with the location identified and all photos. The clerk will print a copy of the email and file it with the completed datasheets.

These steps are outlined in detail in the 5 Minute Meeting '5MM – Identifying Issues on Transmission or Distribution Poles' issued in 2015.

Note: Based on a recent FERC ruling, Transmission Line (T-Line) is no longer authorized to complete Distribution bridging work under Transmission FERC funding. As a result, all Distribution bridging work will be completed under Distribution budget authority. Any nonconformance regarding bridging at the distribution level should be reported using the steps outlined in this section.

1.3.5 Reporting Nonconformance With Access Roads and Gates

Access related work generally falls into several primary categories:

- Create road – there is no road or trail and one is needed
- Vegetation clearing – road is overgrown, or vegetation is encroaching so road needs to be "brushed". Use Brush/Fuel in ET AI App.
- Vegetation in proximity of lines or vegetation in contact with or obstructing structure footings – refer to Section 1.3.3 Reporting Vegetation Nonconformance.
- Road work – can be a range of issues from rockslides and small cutslope slumps of dirt to larger fillslope failures, downed trees or boulders blocking access, rills and gullies (erosion from drainage problems), blown out crossings, etc.
- Watercourse crossings – (e.g., culverts and bridges) blowout or failed.
- Road work encroachment – refer to Section 1.3.7 Reporting Nonconformance with Trespass or Encroachment
- Gates – existing gate is broken or damaged and needs to be replaced, gate has been stolen, or there is no gate and one is needed. (If gate is locked, refer to Section 1.3.7 Reporting Nonconformance with Trespass or Encroachment)

For any type of access issue, the Corrective Work Form (Facility-Damage-Action) approach to creating a new line corrective notification should be followed. By selecting Facility type Road, the appropriate management team will receive the corrective work notification.

If QCR determines access is needed, Damage should be Missing, and Action should be Install. Use Field Comments to indicate type of vehicle for which access is needed – Bucket truck; Pickup; OHV – Razor; Foot trail.

If there is a road in the Right-of-Way, treat it like any road, and Damage should be Brush Fuel. If work area is a hard surface area (e.g., paved or rock) and is greater than 10,000 square feet, approximately longer than ¼ mile of road, then consider this for Capital work. QCR would need to make a note of this in the Field Comments.

1.3.6 Reporting Nonconformance With Boardwalks

Boardwalk repairs and renovation are part of a program based approach that prioritizes all issues to determine the need to reconstruct, repair or abandon the boardwalk to ensure safe and reliable access to facilities. Construction work is complicated due to short construction windows and alignment with environmental agencies permitting cycles. Natural Resources Management (NRM) is working with T-Line to rebuild all boardwalks in the service territory. Currently there are multiple projects underway to rebuild sections of boardwalks; however, complete renovation will take 5-7 years. NRM has completed inspections of all boardwalks which led to the current renovation program. Additional nonconformance notifications are not necessary.

If it is necessary to utilize a boardwalk, all safety precautions listed in 5MM Boardwalk Access Safety, issued 05/29/18, must be followed.

1.3.7 Reporting Nonconformance With Trespass or Encroachment

When encroachments or other uses on PG&E property or easements are identified, they are evaluated for interference with maintaining, operating or constructing electric transmission facilities as described in Utility Procedure TD-1005P-03, "Evaluating Uses of Company Transmission Line Easements by Others" and Utility Standard TD-1005S, "Right-of-Way and Encroachments".

Evaluate the proposed use or encroachment.

- If the activity poses a threat of potential damage to facilities that could cause an immediate danger, contact your supervisor immediately.
- Determine if there is interference and whether permanent access can be maintained for inspections, routine maintenance, reconstruction, growth of facilities and emergency response.
- Confirm there is sufficient conductor-to-ground clearance, radial line clearances and clearances around structures.
- Confirm whether excavation, grading, equipment use or land erosion is impacting pole or tower stability.
- Determine if there are any uses or encroachments that require grounding or there are any prohibited uses (e.g., buildings, structures, pools or wells).
- Refer to TD-1005S, Attachment 1, "Permissible Uses of Pacific Gas and Electric Company (Company) Easements".

Specifically, complete a notification to report any overhead conductors above buildings, swimming pools, wells or similar structures that are not permitted in the easements. The exception are buildings that house the equipment of third-parties, but these are subject to complete and ongoing review.

Verify if the encroachment has already been submitted. If it hasn't, complete a notification in SAP, including digital photographs, if appropriate.

The SAP notification form must indicate the following information:

- Facility Code = Right of Way, Damage Code = Encroachment, Action Code = Remove

The QCR's supervisor reviews the location and sends to electric transmission asset reliability specialist. The electric transmission asset reliability specialist will approve or disapprove of any encroachment or other use. The supervisor will send an email or hard copy to the land agent summarizing:

- How the encroachment or use interferes with utility operation
- What modifications could be implemented to eliminate any interference
- Whether Land Management should abate the encroachment or compel the user to enter into an encroachment agreement

- What measures might be taken to protect facilities during future changes or installations (e.g., maintaining minimum approach distances during construction)
- Any issues that might jeopardize safety or service reliability (e.g., construction near conductors)
- Any steps to meet regulatory requirements (e.g., grounding metal fences)
- Any utility activity that could damage the new use, with a statement that the Company is not liable for such damage.

The land agent will negotiate the Company position with the third party, if required, and discuss the proposed agreement with the electric transmission stakeholders, including the electric transmission reliability supervising specialist and the transmission line maintenance supervisor. The electric transmission reliability supervising specialist and the transmission line maintenance supervisor must review and approve the land agent's proposed agreement, which the land agent will present to the third party. When this process is complete, the land agent will notify the transmission line maintenance supervisor that the work is completed and the transmission line maintenance supervisor will close the notification in SAP.

1.4 Inspection Methodology, Facility, Damage and Action Codes

1.4.1 Inspection Methodology

This methodology establishes a consistent inspection sequence for components and determines the type of inspection that provides the best viewing position for identifying component defects.

Table 2. Inspection Best-View-Position

Description	Aerial Inspection	Ground Inspection (below 10 feet)	Ground Inspection (above 10 feet)	Climbing Inspection (above 10 feet)
Cellular site	X	X		X
Insulators and hardware	X		X	X
Conductor and fittings	X		X	X
Switches and associated elements	X		X	X
Road access	X	X		X
Vegetation	X	X		X
Overhead ground wire / fiber optic cable (OPGW)	X		X	X
Foundations		X		
Anchors and guys		X		X
Structures	X	X		X
Electrical clearances			X	X
Arms/braces	X		X	X

1.4.2 Facility Codes

Defective elements and abnormal conditions identified during inspections and patrols must be identified and recorded using the facility codes and damage codes (FDA codes) as shown in

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Table 3 Overhead Facility, Damage, Corrective Action Codes and Table 4 Underground Facility, Damage, Corrective Action Codes.

The lists in the following tables are not all-inclusive. During inspections, identify any obvious component defects that are not listed. Where "Other" is selected, additional descriptive information must be recorded in the SAP Line Corrective (LC) notification form in the ET Asset Inspection (AI) App to describe the facility, damage, and action prescribed.

IF the QCR identifies inoperable, damaged, misaligned or otherwise non-functional Obstruction Lighting (see 1.18),

THEN the QCR should refer to TD-1001P-03, "Obstruction Lighting Failure Notification Process" for procedure on notifying Federal Aviation Administration (FAA) (e.g., the 15-day periods). The QCR's supervisor reviews the recommendations for repair codes before they are entered in SAP with a Priority Code B.

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Table 3. Overhead Facility, Damage and Corrective Action Codes

Facility	Damage	Action
Anchor-Steel	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Anchor-Wood	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Animal Guard-Steel	Missing	Install
Animal Guard-Wood	Missing	Install
Anode-Tower	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Auto Guy Wire Splice-Steel	No Good/Out of Stdrd	Repair
		Replace
Auto Guy Wire Splice-Wood	No Good/Out of Stdrd	Repair
		Replace
Bay Water-Tower	No Good/Out of Stdrd	Repair
		Replace
Boardwalk	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Conductor-Steel	Debris/Nest/etc.	Remove
	No Good/Out of Stdrd	Repair
		Replace
Conductor-Wood	Debris/Nest/etc.	Remove
	No Good/Out of Stdrd	Repair
		Replace
Connector	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Crossarm-Steel	No Good/Out of Stdrd	Repair
Crossarm-Tower	No Good/Out of Stdrd	Repair
Crossarm-Wood	No Good/Out of Stdrd	Repair
		Replace
Damper-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Damper-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Emergency	Fire	Replace
	Storm Related	Repair
		Replace
Emergency-Steel	Other	Replace
Emergency-Wood	Other	Replace
FAA Battery-Steel	No Good/Out of Stdrd	Replace
FAA Battery-Wood	No Good/Out of Stdrd	Replace
FAA Lighting-Steel	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
FAA Lighting-Wood	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Fault Indicator-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Fault Indicator-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Fee Property	Other	Other
Fence / Gate	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Foundation/Concrete-Tower	Earth Covered Tower	Repair
	No Good/Out of Stdrd	Repair
		Replace
GO95 / Anti Climb	Clearance	Install
	Ground / Clearance	Repair
GO95 Clear Infract-Tower	Clearance	To Be Corrected
GO95 Clear Infract-Wood	Clearance	To Be Corrected
Ground Wire-Steel	No Good/Out of Stdrd	Repair
Ground Wire-Tower	Missing	Install
	No Good/Out of Stdrd	Replace
Ground Wire-Wood	No Good/Out of Stdrd	Repair
Guy Pole-Steel	No Good/Out of Stdrd	Replace
Guy Pole-Wood	No Good/Out of Stdrd	Replace
	Rotten	Replace
		Stub
Guy Stub-Steel	No Good/Out of Stdrd	Replace
Guy Stub-Wood	No Good/Out of Stdrd	Replace
	Rotten	Replace
Guy Wire Mark /Indic-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Guy Wire Mark /Indic-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Guy Wire-Steel	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Guy Wire-Wood	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace

Facility	Damage	Action
Hardware-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Hardware-Tower	Missing	Install
	No Good/Out of Stdrd	Replace
Hardware-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Insulator	Contaminated	Ground Wash
		Helicopter Wash
Insulator Bond Wire-Steel	No Good/Out of Stdrd	Repair
		Replace
Insulator Bond Wire-Wood	No Good/Out of Stdrd	Repair
		Replace
Insulator-Steel	No Good/Out of Stdrd	Repair
		Replace
Insulator-Wood	No Good/Out of Stdrd	Repair
		Replace
Jumper-Steel	No Good/Out of Stdrd	Repair
Jumper-Wood	No Good/Out of Stdrd	Repair
Marker (i.e. signs)-Steel	Missing	Install
	No Good/Out of Stdrd	Install
Marker (i.e. signs)-Wood	Missing	Install
	No Good/Out of Stdrd	Install
Non-Routine Patrol	Investigate	Air Patrol
		Ground Patrol
		Infrared Patrol
Other	Other	Other
Raptor Guard-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Raptor Guard-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Right of Way	Encroachment	Remove
Road	Brush Fuel	Remove
	Encroachment	Remove
	Grade Change	Repair
	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
SCADA-Steel	No Good/Out of Stdrd	Replace
SCADA-Wood	No Good/Out of Stdrd	Replace
Shield Wire / OPGW-Steel	No Good/Out of Stdrd	Repair
		Replace
Shield Wire / OPGW-Wood	No Good/Out of Stdrd	Repair
		Replace
Spacer-Steel	Missing	Install
	No Good/Out of Stdrd	Replace
Spacer-Wood	Missing	Install
	No Good/Out of Stdrd	Replace
Splice-Steel	No Good/Out of Stdrd	Repair
		Replace
Splice-Wood	No Good/Out of Stdrd	Repair
		Replace
Structure-Steel	Anti-Climbing Guard	Install
		Repair
	Debris/Nest/etc.	Remove
	Idle	Remove
	No Good/Out of Stdrd	Repair
		Replace
	Paint/Coating	Other
Structure-Tower	Anti-Climbing Guard	Install
		Repair
	Idle	Remove
	No Good/Out of Stdrd	Repair
		Replace
	Paint/Coating	Repaint
		Replace
	Soil	Remove
Structure-Wood	Debris/Nest/etc.	Remove
	Idle	Remove
	No Good/Out of Stdrd	Repair
		Replace
	Rotten	Replace
		Stub
Switch	Out of Adjustment	Repair
Switch-Steel	No Good/Out of Stdrd	Replace
Switch-Wood	No Good/Out of Stdrd	Repair
		Replace
Tie Wire-Steel	No Good/Out of Stdrd	Replace
Tie Wire-Wood	No Good/Out of Stdrd	Replace
Vegetation	Overgrown	Remove
		Trim
Vegetation-Tower	Overgrown	Cage Clearing
WRO	Request	Agencies (i.e. Muni)
		Other
		Switching

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Table 4. Underground Facility, Damage and Corrective Action Codes

Facility	Damage	Action
Alarm	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Cable	No Good/Out of Stdrd	Repair
		Replace
	Dig In	Repair
		Replace
	Lockout	Ground Patrol
Cable Termination	No Good/Out of Stdrd	Repair
		Replace
Cover/Manhole	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Cathodic Protection-Anode	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Cathodic Protection- Isolator Surge Protector (ISP)	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Cathodic Protection-Rectifier	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Clearance Infraction	Other	Other
Distr Temp Sensor (DTS)	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Emergency	Fire	Repair
		Replace
	Storm	Repair
		Replace
	Other	Replace
		Other
Enclosure/Vault	No Good/Out of Stdrd	Repair
		Replace
	Flooded	Pump
	Debris	Clean
Fee Property	Other	Other
Foundation/Concrete	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
	Earth Covered	Repair
Gas System	Leak	Repair
		Replace
	Inad Pressure	Adjust
Gauge	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Grounds	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace

Facility	Damage	Action
Hardware	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Insulator	No Good/Out of Stdrd	Repair
		Replace
	Contaminated	Clean
Non-Routine Patrol	Lock Out	Ground Patrol
		Infrared Patrol
	Relay	Ground Patrol
		Infrared Patrol
Oil System	Leak	Repair
		Replace
	Inad Pressure	Adjust
Other	Other	Other
Pipe Duct	No Good/Out of Stdrd	Repair
		Replace
Pump Plant-Control Cabinet	No Good/Out of Stdrd	Repair
		Replace
Pump Plant-Pump	No Good/Out of Stdrd	Repair
		Replace
Riser	Missing	Install
	No Good/Out of Stdrd	Replace
Right of Way	Encroachment	Remove
Road	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
	Brush Fuel	Remove
	Encroachment	Remove
	Grade Change	Repair
Right of Way	Encroachment	Remove
SCADA	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Transition Station-Fence/Gate	Missing	Install
	No Good/Out of Stdrd	Repair
		Replace
Transition Station-Lighting	No Good/Out of Stdrd	Repair
		Replace
Transition Station-Lock	Missing	Install
	No Good/Out of Stdrd	Replace
Transition Station-Marker (Aerial, signs, etc)	Missing	Install
	No Good/Out of Stdrd	Install
Vegetation	Overgrown	Remove
		Trim
Work Requested by Others	WRO	Agency
		Other
		Switching

1.4.3 Damage Codes

At least one damage code must be assigned to defective elements found during inspections and patrols. These conditions are listed in Tables 3 and 4.

IF the QCR suspects facilities inspected or patrolled are idle and have no future plans for use, THEN the QCR should indicate on the FDA form in the AI App:

- Facility Code = Structure (Steel, Tower or Wood), Damage Code = Idle, Action Code = Remove

and reference internal standard TD-1003S, "Management of Idle Electric Transmission Line Facilities" to nominate for removal.

1.4.4 Corrective Action Codes

The QCR must recommend the required action(s) to correct the identified abnormal condition(s). These actions are listed in Tables 3 and 4. IF more than one action is required at a facility, THEN each must be identified.

1.5 Assigning Priority Codes and Due Dates

1.5.1 Resolving Abnormal Conditions during Patrol or Inspection

The QCR must complete all possible repairs or replacements to correct abnormal conditions that can be performed safely during the inspection. For abnormal conditions **not** corrected during the inspection, the QCR must prepare a notification based on the inspection datasheets or forms.

In addition, reasonable and appropriate maintenance tasks may be performed by one or two QCRs during inspection.

1. IF the work performed takes **less than 15 minutes** per location for Overhead **OR** Underground transmission,

THEN note the completed maintenance tasks on the following forms:

- For Overhead, on form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet - Typical"
- For Underground, in the "Comments" section of the forms TD-1001M-F06 through TD-1001M-F11, depending on the inspection performed.
- **Do not** record the maintenance tasks in the AI App. For accounting purposes, consider the work to be part of the inspection.

2. IF the work takes **longer than 15 minutes** per location for Overhead **OR** Underground transmission,

THEN consider the time as a separate maintenance PM notification, and record the completed maintenance tasks as follows:

- For Overhead:
    - On form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical."
    - Create the LC notification in the AI App
    - **AND** the clerk will record the completed maintenance task(s) in the SAP database
    - **AND** record the completed maintenance in your time card with the appropriate accounting.
- For Underground:
    - In the "Comments" section of forms TD-1001M-F06 through TD-1001M-F11, depending on the inspection performed
    - Create the LC notification in the AI App
    - **AND** the clerk will record the completed maintenance task(s) in the SAP database

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- **AND** record the completed maintenance tasks in your time card with the appropriate accounting.

1.5.2 Assessing Conditions

Evaluate the condition of the facilities at each location when performing patrols, inspections, or post-checking the completed work. Section 2. Inspections, identifies many of the field conditions that need to be evaluated.

Once identified, the QCR determines the severity of the condition, the risk factors, the appropriate priority level, and a reasonable time frame to plan, design, and complete any required corrective work. Recommendations of an appropriate priority/repair time frame by the QCR are based on experience and judgment.

In addition, the QCR must consider the following risk factors and conditions encountered in the field when recommending priority/repair codes:

- The risk of exposure to the public, workers, or employees
- The abnormality encountered
- Risks if the condition continues to deteriorate
- Likelihood of facility failure
- Impact of the failure to system reliability, customers and service, and/or the potential for injury

Table 5 lists the priority codes and the associated time frames for typical response/repair action.

Table 5. Priority Codes

Priority Code	Priority Description
A	The condition is urgent and requires **immediate** response and continued action until the condition is repaired or no longer presents a potential hazard. SAP due date will be 30 days to allow time for post-construction processes and notification close-out.
B	Corrective action is required within **3 months** from the date the condition is identified. The condition must be reported to the transmission line supervisor as soon as practical.
E	Corrective action is required within **12 months** from the date the condition is identified.
F	Corrective action is recommended within **24 months** from the date the condition is identified, (due beyond 12 months, not to exceed 24 months). Requires Director approval.

1. QCRs must report immediately any “Priority Code A” abnormal condition to the transmission line supervisor and GCC.
2. In addition, QCRs must report any “Priority Code B” condition to the transmission line supervisor as soon as practical, to ensure that correction occurs within the appropriate time.

During the Fire Safety Rulemaking in 2017 and 2018, new GO95 requirements impacting transmission lines were adopted, including the items listed below.

- Rule 21.2D added a definition for High Fire-Threat Districts (HFTD)

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  - Zone 1 – Tier 1 High Hazard Zones (HHZ) on the Tree Mortality Map
  - Tier 2 – areas on the CPUC Fire-Threat Map where there is an elevated risk for destructive utility-associated wildfires
  - Tier 3 – areas on the CPUC Fire-Threat Map where there is an extreme risk for destructive utility-associated wildfires
  - Where Zone 1 overlaps with Tier 2 and Tier 3 areas, the strictest regulations apply
- Rule 18 added requirements for the prioritization and correction of safety hazards in HFTDs. The changes impacting transmission were:
  - Shortened not to exceed timelines for correcting Level 2 safety hazards in HFTDs
    - 6 months in Tier 3 (fully implemented 9/1/18)
    - 12 months in Tier 2 (fully implemented 6/30/19)
- Appendices I and J provide examples of facility conditions in different situations with different corrective timelines based on the risk and level of impact on safety and reliability

Drawing 072148 Fire Responsibility and Wildland Fire Areas has been updated to reflect the CPUC HFTDs. ET GIS, MapGuide and Google Earth have also been updated with this information.

Priority E and F notifications for facilities that are located in Tier 3 of the HFTD map will be assigned dates with a maximum 6 month duration, and facilities located in Tier 2 of the HFTD map will be assigned dates with a maximum 12 month duration. This maximum duration will be set in SAP. If the notification is determined to be non-threatening (e.g., not a Level 2 safety hazard that would result in a fire risk), the asset strategist will code it as non-threatening and adjust the Recommended Repair Date based on the Priority Code.

There are no changes to Table 1 Vegetation Clearance Distance.

The following is a list of conditions from GO95, Appendices I and J for transmission line overhead facilities that may create a fire risk (Level 2 conditions) in the HFTDs, but it is not all-inclusive. In addition, any conditions found on distribution assets should be reported per Section 1.3.4 Reporting Other Nonconformances with Distribution Facilities.

- Excessively sagging conductors
- Inadequate separation
- Broken insulators compromising adequate insulation values
- Damaged equipment (e.g. switches)
- Equipment found as burnt, flashed or with evidence of arcing (e.g., insulators, jumpers)
- Deteriorated crossarms
- Damaged or deteriorated bird guards
- Damaged or excessively leaning towers or poles
- Sagging guys
- Insufficient clearance from vegetation
- Vegetation causing strain or abrasion
- Missing or damaged wood pole bridging on underbuild

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Examples of conditions that may not create a fire risk (non-threatening) in the HFTDs and associated notifications and are not subject to the shorter HFTD durations are shown below. The asset strategist will code it as non-threatening and adjust the Recommended Repair Date based on the Priority Code.

- Missing high voltage sign in remote locations, inaccessible to pedestrians or vehicles
- Damaged or missing guy marker in remote locations, inaccessible to pedestrians or vehicles
- Anchor guy with minimal slack where a pole is straight or leaning towards the anchor
- Climbing space obstruction from vegetation when it does not prevent work from being done or does not violate Rule 35
- Damaged or loose hardware that is not in the climbing space and does not pose a risk to employees or the public
- Missing or damaged bolt covers where only exposure is to the QEWs

1.5.3 Notifications Extending Beyond Due Date

It is the Company's intent to correct identified abnormal conditions by the established due date. With the exception of notifications approved through the LC past due exemption process, due dates will not be changed or extended. Past due notifications that are not approved for exemption must be completed as soon as practicable. Factors that can drive notifications to extend beyond the due date include, but are not limited to, the following items:

- Inability to obtain clearances, materials, equipment or access
- Environmental permitting restrictions
- Interference from weather
- Subsequent testing or reevaluation of the actual condition

1.5.3.1 LC Notification Past Due Exemption Process

In order for a notification to be exempted from internal late tag reporting and officially 'exempted', the LC notification past due exemption process must be followed to ensure field conditions will permit an extension and that proper documentation is included in SAP. Follow the procedures in TD-1001M-JA03, "Transmission LC Past Due Exemption Process" and utilize TD-1001M-F17, "SS LC XMPT Req Form (Notif)".

The LC Past Due Exemption Process requires:

1) A field visit by a PG&E QEW to assess the current field condition identified and confirm it is safe to defer completion of the work to a later date
2) Photo documentation of the current condition
3) EDRS approval from the Asset Strategist, Supervisor Maintenance and Compliance, Superintendent AND the Transmission Line Senior Director with documentation attached in SAP and a CC to the Manager Work Plan and Maintenance Strategy

NOTE: If it is unsafe to defer completion of the notification, PG&E musts continue to pursue other methods of completing repairs prior to the required end date.

An LC Notification due date exemption should not be requested until reasonable effort has been made to complete the notification by its required end date (also known as due date).

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GO95 Rule 18A Part 2b states that "Correction times may be extended under reasonable circumstances" and lists several examples of reasonable circumstances. TD-1001M-JA03, "Transmission LC Past Due Exemption Process", elaborates on the sample circumstances listed in Rule 18A and outlines the PG&E process for requesting and documenting due date exemptions for corrective work.

LC notifications for maintenance work that have met the circumstances outlined in that document, and have been approved through the exemption request process:

- Will be exempt from meeting their Required End Dates
- Will be required to meet a new due date, an updated Required End Date (shown as Funded Repair Date in SAP)
- Will not be included in internal late LC Notification reports

All exemption requests must be made no later than the notification required end date, with the exception of notifications that meet the Major Emergencies criteria outlined below. Examples of conditions that may qualify for an Exemption include:

- **Third Party Refusals.** Examples:
    - Refusals due to right-of-way conflicts
    - Prevention of work due to issues with third party utilities
    - Inability to acquire clearances due to CAISO limitations or refusals
- **No Access.** Example:
    - Field conditions, such as landslides, water, or snow create an unsafe environment for crews to complete work
- **Permit Delays.** Examples:
    - Delays in obtaining environmental or land permits to complete work. Permit request should be submitted at least 60 days prior to the required end date.
    - Delays due to city moratoriums on work
- **Major Emergencies.** Examples:
    - Resources diverted due to Major emergencies, such as fires, severe weather conditions, etc., and the LC required end date falls between the first day of the OEC activation and 30 calendar days after the OEC deactivation (order status must be released to construction
    - Resources diverted due to routine emergencies, such as car poles, do not qualify
- **Unavoidable Internal Delays**
    - For example, pending substation work that prohibits transmission work from being completed until the substation work is completed. Not limited to substation; can be due to distribution, power generation, etc.

Internal process delays do not qualify for exemption. Such exemption requests will be reviewed by the LC Program Manager on a case-by-case basis. Examples of internal process delays include, but are not limited to:

- Delays in job cycle handoffs, such as the handoffs of job packages to construction crews
- Job scope changes
- Scheduling work beyond the notification Required End Date to minimize the impact of outages due to customers or bundling work for crew efficiencies

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- Permitting/environmental delays due to PG&E's internal process. For example, a permit is not obtained in time. PG&E had to opportunity to file a permit sooner, but did not do so due to internal process delays.
- Unavailability of materials
- Inability to obtain a clearance before the due date as a result of GCC constraints

Prior to the submittal of an Exemption request, a qualified PG&E employee must complete a field visit to assess the current field condition identified on the LC notification and confirm it is safe to defer the completion of the work to a later date. At least one picture is required to document the current field condition (take additional pictures as needed). All requests require a field safety assessment and photo including static FDA. **Exception**: A field visit/safety picture is not required if all the requirements below are met:

- It meets the major emergency criteria
- Is NOT a Priority B tag
- It will be worked within 2 months from the required end date

If it is unsafe to defer the notification, PG&E must continue to pursue other methods of completing repairs by the prior established notification required end date. For example, if there is an environmental issue and it is unsafe to defer the work, PG&E must communicate with the local agency that the work needs to be completed prior to the due date and that it is unsafe to defer.

1.5.3.2 LC Notification with Rejected Exemptions OR Past Due Date Process

For any notification for which the exemption was rejected and/or is past due and did not meet the exemption criteria, an EDRS which includes the reason will need to be routed to the Regional Superintendent for approval. The EDRS must CC the Transmission Line Senior Director, Manager Work Plan and Maintenance Strategy, Supervisor Maintenance and Compliance and local Asset Strategist.

1.6 Creating and Closing Inspection/Patrol and Maintenance Records

All inspection and patrol records must be filled out completely and accurately and maintained in the appropriate files. Refer to TD1001M-JA01, "Patrol, Inspection and Closing Process", for directions on completing and reviewing the forms and the SAP closing process. Refer to Appendix E: Line Patrol File Guidelines for additional requirements on how to complete the forms and how to store the files. Section 1.6.1 Inspection/Patrol Records – Records and Deadlines provides specific timelines for QCRs, clerks, supervisors and/or SAP "gatekeepers" to enter all information into SAP.

1.6.1 Inspection/Patrol Records

Overhead Patrols: Use the overhead ETPM Form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," to document any abnormal conditions as they are encountered in the field. See 8.Appendix C: Links to Forms and Flowcharts, for a list of and links to overhead inspection/patrol datasheets.

Overhead Inspections: Use the object list, TD-1001M-F05, "Object List - Typical" and the datasheet TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," to document inspections and to verify the assets. See 8.Appendix C: Links to Forms and Flowcharts, for a list of and links to overhead inspection/patrol datasheets and object lists.

Underground: Use the underground transmission inspection sheets and forms TD-1001M-F06 through TD-1001M-F11, depending on the inspection performed, to document test results

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and any abnormal conditions encountered in the field. See Section 5.2 Underground Job Aid for Maintenance Procedures for typical maintenance procedures and corrective actions.

Records and Deadlines: After an inspection, completed overhead and underground inspection/patrol datasheets and inspection/patrol forms must be signed, dated, and submitted to the transmission line supervisor for review and approval. Notwithstanding extraordinary circumstances, such as a major emergency response, upon completion of the field patrol or inspection, QCRs are expected to:

- Submit required paperwork to the local clerk within five (5) business days or by the end of the calendar month the patrol was completed in, whichever is sooner.

Supervisors review forms (either paper or electronic) for accuracy, including completion of all fields, confirm the priority code and due date, confirm clearance requirements or hot work, ensure ink was used on paper forms and confirm signature, date and LAN ID. The supervisor or other SAP gatekeeper is expected to approve or reject all SAP staging notifications within five (5) business days of their entry into SAP gatekeeper module.

Timeline Detail:

1. QCR finds abnormal condition during inspection/patrol on Day 00
2. QCR delivers completed forms to clerk by business Day 05
3. Clerk enters inspection and patrol information into the SAP system by business Day 15.
4. Gatekeeper reviews and rejects/modifies/approves S5 to create new LC by business Day 20, thus establishes SAP notifications within 20 business days to facilitate proper work planning, scheduling, and to correct abnormal conditions by the required due dates.
5. Document the reason for non-routine and emergency patrols on the notification.

The overhead TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," and the underground transmission "Routine" and "Detailed" inspection forms (TD-1001M-F06 through TD-1001M-F11, depending on the inspection performed) **must** contain, but is not limited to, the following information:

- Name of the QCR
- Date of the inspection/patrol
- Name of the circuit inspected/patrolled
- Structure number/s
- FDA condition
  - Facility found abnormal
  - Damage indicated
  - Action, such as recommended maintenance activities and the priority of these recommendations
- Significant comments regarding special work requirements, access notes, etc.

1.6.2 Maintenance Records

Record routine, non-routine, and emergency maintenance performed in the SAP database or on inspection/patrol datasheets. Maintain records in accordance with Section 1. General Inspection and Patrol Procedures, Section 1.1 Record Keeping and Section 1.5.1 Resolving Abnormal Conditions during Patrol or Inspection. These records **must** include, at a minimum, the person responsible for performing the maintenance, the date of the maintenance, the name of the circuit, the facility maintained, and a description of the maintenance performed.

Keep these records in the SAP database and field inspection and patrol files at the responsible transmission line supervisor's headquarters.

1.6.3 Asset Creation

As assets observed in the field differ from SAP object lists, drawings, schematics, or other formal references, they should be updated per the Electric Transmission Geographic Information System (ET GIS) asset creation or maintenance processes (ET GIS Process maps 1.1 through 1.16). These processes apply to overhead and underground assets. Following the ET GIS asset creation and maintenance processes will ensure the transmission asset registry and mapping systems are kept current with actual field conditions. New assets or removed assets must also be entered in ET GIS. Use TD-1001M-F13, "Request to Add Equipment Records to the Asset Registry" to add new equipment. Use TD-1001M-F14, "Request to Delete Equipment Records to WM SAP" to delete equipment in ET GIS. Refer to ET GIS SAP – Request for Work Job Aid – Creation for specific details.

1.7 Overhead Job Aid for Assigning Priority Codes

The inspector's primary responsibility in an overhead electric facility inspection or patrol is to examine and record the specific condition of the facilities. This requires a detailed evaluation (e.g., visual observation, and potentially, use of measuring devices, tools, or routine diagnostic test) to determine if there are any structural problems or hazards that will adversely impact safety, service reliability, or asset life, and to evaluate when each abnormal condition identified warrants corrective action. Do not create corrective maintenance notifications for abnormal conditions that do not require corrective action prior to the next scheduled inspection or patrol.

Use the guidelines in Table 6. Guide for Assigning Priority Codes, to grade abnormal conditions that will adversely impact safety, service reliability, or asset life, that, in the judgment of the inspector, require corrective action before the next scheduled inspection or patrols. Table 6. does not provide a comprehensive list of conditions that can be encountered. The Priority Code levels are for typical adverse conditions and must be adjusted up or down based on the inspector's judgment of the actual condition observed. See the following examples:

Example 1:

A missing damper is identified during a routine aerial patrol.

- Table 3. Overhead Facility, Damage and Corrective Action Codes Facility, Damage and Corrective Action Codes, provides the facility code for missing damper.
- Referring to Table 6. , E is a typical Priority Code for a missing damper.
- The inspection datasheet is completed with the following information:
  - Facility Code: Damper-Steel or Damper-Wood
  - Damage Code: Missing
  - Action Code: Install

NOTE: If the inspector is aware that the transmission line with the missing damper has an aged conductor with a history of vibration-related problems, the inspector may, based on his knowledge of the line, assign a Priority Code B (3 months).

Example 2:

A loose "Danger High-Voltage" sign is identified during a routine ground patrol at a wood pole.

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- Table 3. Overhead Facility, Damage and Corrective Action Codes Facility, Damage and Corrective Action Codes, provide loose markers.
- Table 6. Guide for Assigning Priority Codes, a typical Priority Code for a loose “Danger High-Voltage” sign would be E.
- The inspection datasheet is completed with the following information:
  - Facility Code: Marker (i.e. signs)-Wood
  - Damage Code: No Good/Out of Stdrd
  - Action Code: Install

Example 3:

A wood pole is identified with significant woodpecker damage during a routine ground patrol.

- Table 3. Overhead Facility, Damage and Corrective Action Codes Facility, Damage and Corrective Action Codes, for structure wood damage.
- Table 6. Guide for Assigning Priority Codes, a typical Priority Code for severe woodpecker damage would be B.
- The inspection datasheet is completed with the following information:
  - Facility Code: Structure-Wood
  - Damage Code: No Good/Out of Stdrd
  - Action Code: Replace

Table 6. Guide for Assigning Priority Codes

Component	Priority Code				
	A (Immediate)	**B (3 months)**	**E (12 months)**		**F (24 months)**
Anchor-Steel **Anchor-Wood** **Guy Wire-Steel** **Guy Wire-Wood**	Rust >50% material loss Worn >50% material loss Cracked >50% Broken or Missing critical members	Cracked 33 to 50% Over tension >50% Broken or missing secondary members Clearance from energized conductors	Rust 30 - 50% material loss Worn 30 - 50% material loss Cracked 5 to 33% Soil Movement/slide/ standing water Slack storm guy	Over tension 10 to 50% Twisted	**No 24 month tags**
Conductor-Steel **Conductor-Wood** **Damper-Steel** **Damper-Wood**	Rust >50% material loss Cracked >50% Gunshot >20% of strands broken Arcing	Cracked 33 to 50% Gunshot 15 to 20% of strands broken Corrosion (heavy) Conductor clearances Broken ground wire or tie wire Broken spacer or connector Loose connector, tie wire, or weight Twisted bundled conductor	Rust 10 - 50% material loss Broken damper Missing damper Bent damper Out of position damper	Cracked 5 to 33% Gunshot 5 to 15% of strands broken Corrosion (medium) Vibrating	**No 24 month tags**
Electrical clearances: **GO95 Clear Infract-Tower** **GO95 Clear Infract-Wood**	Tree contacting line or showing signs of contact (burnt leaves or limbs)	Circuit-to-circuit Burnt Trees Clearance < G.O. 95	Ground Clearance < G.O. 95	Grade change (Ground Clearance < G.O. 95)	**No 24 month tags**

Component	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Foundation/ **Concrete-Tower**	Significant soil erosion or movement causing lack of support around the foundation. Damage to, or separation of, main structural support members or stub angle tower leg that compromises structural integrity	Rust (rebar exposed with >50% material loss) Cracked (cracks >1/2") Earth covered (covering steel member) Buckled rebar, concrete spalling Soil movement (movement causing significant bowing of tower members)	Not sealed Soil movement (Slide 10 to 15 inches) Bent Exposed wood pile	Rust 30 - 50% material loss Cracked (cracks > 1/16") Earth covered/ buried foundation Buried steel stubs (due to potential corrosion) Twisted Soil movement (e.g., erosion or piled dirt, movement causing some bowing of tower main legs)	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews
Insulator **Insulator-Steel** **Insulator-Wood** (Insulators with these conditions, see Table 7. , Flashed Cracked, Broken, Gunshot, Chipped >1½ inches)	Rust >50% material loss Worn >50% material loss Cracked >50% Contaminated (arcing)	Cracked 33 to 50% Contaminated (heavy) Tracking (heavy)	Rust 30 - 50% material loss Worn 30 - 50% material loss Contaminated (medium) Tracking (medium)	Cracked 5 to 33%	**No 24 month tags**
Switch **Switch-Steel** **Switch-Wood** (Switch insulators with these conditions, see Table 7. , Flashed,	Rust >50% material loss Cracked >50% Arcing Open (unlocked) Inoperable	Cracked 33 to 50% Corrosion (heavy) Contaminated (heavy) Tracking (heavy) Burnt **Hot** Loose	Rust 30 - 50% material loss Contaminated (medium) Tracking (medium) Heating Bent/Bowed	Cracked 5 to 33% Corrosion (medium)	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials

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Component	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Cracked, Broken, Gunshot, Chipped >1½ inches)		Broken Out of adjustment Missing			and environmental reviews
Structure-Steel **Structure-Tower**	Critical/Main member: Rust >50% material loss Cracked >33% Worn >50% material loss Damage to main structural support members compromising structural integrity Internal corrosion of tubular memberrs Broken (member) Missing (member)	Missing bolts or single bolt connection on critical member Single bolt mission of multi-bolt connection	Rust 30 - 50% material loss Pack-rust at joints, crevices or overlaps Cracked 10 to 33% Worn 30 - 50% material loss Buckled/bent Out of plumb >3 feet	Vibrating members Twisted Out of plumb 1 to 3 feet Loose bolts, etc.	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews
Markers (i.e. signs)-Steel **Markers (i.e. signs)-Wood**	Facilities or structures which have a recent history of trespass or third-party unauthorized access	–	Cracked Broken Loose Missing	–	**No 24 month tags**
Right of Way **Vegetation** **Vegetation-Tower**	Tree contacting line or showing signs of contact (burnt leaves or limbs) Encroachments	Tree clearance < G.O. 95 Clearances < G.O. 95	–	Grade change (Ground Clearance < G.O. 95)	Encroachments to be resolved via Land Management

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Component	Priority Code				
	A (Immediate)	**B (3 months)**	**E (12 months)**		**F (24 months)**
Road	If posing threat to facilities due to wash out or land motion				Access road repair or replacement
Boardwalk (not necessary to submit an LC Notification)					
SCADA-Steel **SCADA-Wood**		Repair SCADA			Replace or install SCADA
Structure-Wood	Burnt >50% material loss	Burnt 40-50% material loss Cracked >50% Broken Slide >15 feet Out of plumb >15 feet Soil Movement (Erosion >3 feet in the ground) Worn/woodpecker damage (severe)	Burnt 20-40% material loss Twisted (severe) Slide 10 to 15 feet Out of plumb 4 to 15 feet Erosion 3 to 4 feet in the ground Standing water	Cracked 10 to 50% Twisted (medium) Erosion >4 feet in the ground Worn/woodpecker damage (medium) Earth covered	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews
Idle Facilities (any facility type)	Removal of idle facilities posing an immediate threat to life, property or reliability	-	-	-	For planning optimization of removal of non-emergency idle facilities

Note: If, on performing the required visual inspection and hammer test, the QCR believes the pole to be suspect, the pole must be tested further in accordance with Utility Standard TD-2325S, "Wood Pole Inspection, Testing, and Maintenance," and Work ProcedureTD-2325P-01, "Wood Poles - Testing, Reinforcing and Reusing." This standard establishes the requirements for inspecting and testing the structural integrity of wood poles, the requirements for reinforcing and reusing, and requirements for testing wood poles prior to climbing. After completing the pole inspection, the QCR must complete the TD-2325P-01-F01, "Attachment 1 - Pole Inspection/Test Report," and forward it to the supervisor. The supervisor will forward it to the estimating group for further evaluation and appropriate corrective action identification.

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1.8 Overhead Job Aid for Insulator Replacement and Priority Codes

1.8.1 Insulator Strength and Loading

Usually, dead-end insulators are loaded to a higher percentage of their design strength than are suspension insulators. Typically, suspension insulators are loaded 30% to 50% of the design strength of dead-end insulators.

Listed below are the criteria for replacing insulators during maintenance:

- Replace suspension and dead-end insulators if they exhibit signs of deterioration or corrosion or have been subjected to some unusual loading condition. If insulators are in good condition, loading and unloading the insulator string during routine maintenance will not degrade the insulators.
- Replace all suspension or dead-end insulators that have been affected by shock loading (impact loads that exceed the normal loading and are generally associated with broken wire conditions on steel structures with normal sag tensions that exceed 3,000 pounds).
- All insulators not listed as approved for purchase or as a salvable substitute are obsolete and must not be used. Salvable substitute insulators more than 20 years old are not to be used and should be disposed of. Salvable substitute insulators less than 20 years old that have not been in service may be used. Suspension type porcelain insulators shall not be used on new construction without approval from transmission line standards engineer per TD-015014B-001, "Approval Required for Installation Suspension Type Porcelain Insulators".

1.8.2 Insulator Conditions

1.8.2.1 Broken Insulators

Broken insulators have one or more of the following conditions:

- Glass or porcelain is broken and only the hub is remaining.
- One or more skirts are broken and a piece is missing.
- The insulator is cracked.

1.8.2.2 Chipped Insulators

Chipped insulators generally have little effect on the reliability of the insulator and do not need to be addressed, unless one or more of the following conditions is present:

- A crack extends from the chip.
- The chip is larger than 2" in diameter.
- The chip is located next to a grouted fitting where it will trap water and could freeze.

If any of the above conditions exist, evaluate the insulator like it was a broken insulator. Use the proper Priority Code listed in Table 7.

1.8.2.3 Flashed Insulators

The priority for a flashed insulator depends on the type of insulator. The following information provides some direction for assigning priorities to the various types of insulators:

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- **Porcelain** - Replace the entire insulator string or post insulator. Depending on the weather conditions, contamination present on the insulator, and the contamination area, assign Priority Code A, B, or E. If assigning a Priority Code B or E, the insulator must be washed or cleaned as soon as practical to prevent it from flashing over again before it is replaced.
- **Glass** - Glass insulators do not always need to be replaced when flashed. If the glass is intact, cleaning the insulator usually restores its electrical strength. However, if the glass is broken, replace the insulator(s) and assign the Priority Code using the criteria for broken insulators.
- **Non-Ceramic** - If the flashover damaged the insulator sheds or end fittings, assign Priority Code A and replace the insulator. If there is no visible damage to the insulator skirts or end fittings, the insulator does not need to be replaced and does not need a Priority Code.

1.8.2.4 Dirty/Contaminated Insulator Cleaning

Perform insulator washing based on local environmental conditions, operating experience, and the predetermined wash cycles established in SAP.

- Wash insulators in accordance with the TD-1257M, "Insulator Cleaning Manual". The TD-1257M, "Insulator Cleaning Manual" provides guidance on contamination assessment and insulator cleaning frequency.
- Maintenance plans must be created in SAP for circuits that require annual (or more frequent) insulator washing, as determined by the local transmission line maintenance supervisor, based on insulator contamination and performance.
- By agreement, maintenance plans must be created in SAP for Diablo Canyon Power Plant (DCPP) 500kV and 230kV transmission line circuits utilizing frequencies specified in Section 2.1.3 and Table 15. Specific wash instructions are provided for structures near DCPP and Morro Bay Power Plant in Section 6.6.

1.8.3 Assigning Insulator Priority Codes

Table 7. Guide for Replacing Damaged Insulators, provides guidance for assigning the proper Priority Code for broken insulator strings. Use this information for the various voltages, types of construction, and contamination districts to provide consistent responses and ensure system reliability.

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Table 7. Guide for Replacing Damaged Insulators

Voltage	Configuration	Contamination District	G.O. 95 Minimum Requirements: Dry Flashover *	G.O. 95 Minimum Requirements: # of Units	Design # of Units	Minimum # of Units	# of Broken Units: 1 (Priority Code)	# of Broken Units: 2 or more (Priority Code)
500kV	Dead-end	AAA	1,190 kV	23	34	32	E	B
	Dead-end	B, C, D			28	26	E	B
	Vee String	AAA			36	34	E	B
	Vee String	B, C, D			28	26	E	B
	Suspension	AAA			34	32	E	B
	Suspension	B, C, D			25	23	E	B
230kV	Dead-end	AAA	582 kV	12	24	20	E	B
	Dead-end	A			22	18	E	B
	Dead-end	B, C, D			17	15	E	B
	Suspension	AAA			16	13	E	B
	Suspension	A, B, C, D			15	13	E	B
115kV	Dead-end	AAA	333 kV	6	12	10	E	B
	Dead-end	A			11	9	E	B
	Dead-end	B			10	8	E	B
	Dead-end	C, D			9	8	E	B
	Suspension	AAA			10	6	E	B
	Suspension	A, B			9	6	E	B
	Suspension	C, D			8	6	E	B
60/70kV	Dead-end	AAA	180 kV	3	7	5	E	B
	Dead-end	A, B			7	5	E	B
	Dead-end	C, D			6	5	E	B
	Suspension	AAA, A, B			5	3	E	B
	Suspension	C, D			4	3	E	B

* The dry flashover (FO) is based on ANSI C29.1 test procedures.

Notes:

1. This table is based on dry flashover insulator characteristics. If possible, replace insulators before the onset of wet weather.
2. Consider local conditions. Insulator strings near the coast, at Diablo Canyon, 500 kV, etc., may be more critical and replaced more urgently.
3. Adjust the Priority Code based on the various conditions that may exist, including
   - Priority Code A (fix immediately) for 2 or more insulators less than the G.O. 95 requirement
   - Priority Code B (fix within 3 months) for 1 insulator or less than the G.O. 95 requirement
   - Priority Code E (fix within 1 year) if less than design, but more than the G.O. 95 requirement
4. For barehand work, refer to the TD-1248M, "Electric Transmission Live Line Barehand Work Procedures Manual" for the minimum number of insulators and clearance requirements.
5. If an insulator string has broken insulators and the remaining number of good insulators in the string exceeds the design number of units, assign Priority Code E.

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1.9 Overhead Job Aid for Transmission Line Steel Structures

1.9.1 General

Inspect transmission line towers on a regular basis. If abnormal conditions are found during this process, use ET AI App to record the physical condition of the structure. It is recommended to use digital pictures in conjunction with this form.

See Table 6. Guide for Assigning Priority Codes, for information about assigning notification priorities for the condition found.

1.9.2 Analysis of Condition by Engineering

See Section 1.16 Equipment Replacement ,.

1.9.3 Detailed Description for Repairing Deteriorated Steel Structures

Table 8. Detailed Description for Repairing Deteriorated Steel Structures

Priority Code	Characteristics	Action	Notes
A: Immediate attention required.	Major corrosion (severe rusting on more than 50% of the structure steel and isolated pitting) and/or physical damage to main structural members, compromising structural integrity. Severely rusted legs, packed-rust at bolted joints, and/or internal corrosion of tubular members. Catastrophic failure of structure is an immediate possibility.	Replace the structure to avoid a catastrophic failure.	
B: Attention required within 3 months.	Members and/or bolts missing.	Repair as needed to restore structural integrity.	
E: Attention required within 12 months.	Rust 30-50% material loss. Moderate corrosion (surface rusting on more than 50% of the structures) and loss of galvanizing. Reddish brown rust of zinc-iron alloy with less than a mil of zinc left on the surface. Pack-rust at joints, crevices, or overlaps.	Repair as needed to restore structural integrity. Replace areas of isolated steel members with serious pack-rust, if possible. If pack-rust is present, contact transmission line civil engineering.	**CAUTION:** If pack-rust is significant and the area(s) cannot be replaced, replace the structure within 5 years.

	Physical damage on one or more easily replaceable members. Any coating, if previously applied over galvanizing, is more than 50% deteriorated, exposing surface rust. Any coating at steel-concrete transition (aka stub-concrete interface) is more than 50% deteriorated exposing surface rust. Any soil or vegetation is within 18 inches or covering greater than 30 inches of stub-concrete interface Vibrating or twisted members. Loose bolts.	Modify the structure according to civil engineering recommendations to eliminate vibrations. Replace twisted members. Clean rust from stub-concrete interface, wipe dust clean with denatured alcohol or isopropyl alcohol, and recoat with approved coating, typically black bitu-mastic material. Remove soil/vegetation or add proper compacted medium and/or reinforce footing according to civil engineering recommendations.	
Priority Code	**Characteristics**	**Action**	**Notes**
F: Attention required within 24 months.	No significant evidence of structural or surface deterioration or corrosion. Galvanizing still in good condition with a minimum of 2 mils zinc present. Any coating previously applied over galvanizing is in good condition with no significant deterioration.	Inspect at least every 5 years as a precaution.	Long lead time material required. Structure replacement. Environmental/permitting requirements. No Attention Required for at Least 5 Years.

1.10 Overhead Job Aid for 500 kV Climbing Inspections

1.10.1 General

Inspect 500 kV transmission towers on a regular basis. Use ETPM Form TD-1001M-F03, "500kV Climbing Inspection Form and Tower Diagrams," to record the physical condition of the structure. Digital pictures may be used in conjunction with this form. Enter the conditions found in the SAP system and submit the form to the transmission line asset management supervisor in accordance with the instructions on the form. TD1001M-JA02, "Detailed Climbing Inspection Job Aid" and TD-1001M-JA04, "Identifying Levels of Corrosion and Foundation Condition on Transmission Line Structures and Supports" should be referenced for additional instructions to complete the forms.

1.10.2 500 kV Climbing Inspection Form and Tower Diagrams

TD-1001M-F03 provides a ready reference to ensure a thorough inspection. It is intended that the items on Pages 2-4 of the form will be inspected during the climbing inspection. Page 5 of the form provides a reference to aid the inspector in recording other line-related component deficiencies that might be noticed during the inspection.

The "Tower Diagrams" part of TD-1001M-F03 provides a framework to record guy tensions.

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1.11 Overhead Job Aid for Conductor Inspections

1.11.1 General

Patrol and inspect transmission lines and their associated conductors on a regular basis. If an abnormal condition is found during this process, use the ET AI App to record the physical condition of the conductor. Refer to Table 6. Guide for Assigning Priority Codes for information about assigning Priority Codes.

1.11.2 Analysis of Condition by Engineering

If a conductor is not in immediate risk of failure, but is considered beyond economical repair, follow the process described in Section 1.16 Equipment Replacement .

1.11.3 OPGW and ADSS Cable Inspection

Some installations of OPGW have been deteriorating due to the non-standard installation of the hanging hardware, as well as internal corrosion build up. The non-standard installation includes, but is not limited to, the following: incorrect placement of U-Bolt Dead-End spacer bar, incorrect U-Bolt Dead-End ground types, missing vibration dampers, improperly placed down-lead cushions, and not maintaining minimum separation between OPGW cables on splice towers. This situation has resulted in broken outer layer OPGW strands and corrosion. Some installations of ADSS cable have been deteriorating due to dry band arcing/tracking. This is the situation where the electric field is too high for the ADSS cable to survive and over time the electric field has burned through the cable jacket. During patrols and inspections, as possible, examine the cable and hardware installation of the OPGW and ADSS cable. If you see signs of tracking, broken strands, separating strands, bare fiber or exposed buffer tubes, create an SAP notification indicating the following:

- Facility Code = Shield Wire/OPGW (Steel or Wood), Damage Code = No Good/Out of Stdrd, Action Code = Repair or Replace

Take photos as possible, with comments describing the condition found and if there are recommendations for repairing or replacing.

1.12 Overhead Job Aid for Switch Inspection

1.12.1 General

Transmission line switches must be inspected in accordance with circuit inspection cycles, and maintained in accordance with FDA Processes as per TD-1006P-02, “Switch Maintenance and Inspection Program for Electric Transmission” and TD-1006P-02-JA-01 “Electric Transmission Line Switch Inspection/Function Test Job Aid”.

1.12.2 Overhead Switch Numbering

Transmission line switches must be numbered in accordance with TD-1006B-004 “Procedure for Marking Duplicate Transmission Switches”.

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1.12.3 Analysis of Condition by Engineering

If a switch is not in immediate risk of failure, but is considered beyond economical repair, follow the process described in Section 1.16 Equipment Replacement ,.

1.13 Removal of Metal Fence Attachments

Third-party attachments of metal fences (cyclone, barbed wire, etc.) to steel towers, wood poles, and/or transmission down guys is not permitted. Remove all attachments and instruct the fence owner that this attachment or contact is not allowed.

1.14 Overloaded Transmission Line Poles

1.14.1 General

Over-stressed/overloaded wood poles can occur as a result of underbuilt distribution facilities, underbuilt third-party facilities, or as a result of reconductoring without an associated pole replacement.

1.14.2 Required Action

If there is any reason to believe or suspect that wood poles are overloaded or over stressed, record specific information about the situation and send it to the appropriate transmission line estimating office for further action. The information recorded must include, but is not limited to, the following items:

- Line name, structure number, and location
- Wire size, cable size, span length, attachment height
- Pole size and class
- Any additional information deemed necessary for identification or explanation

Complete the notification form in the ET AI App using the FDA codes provided in Section 1.4. Inspection Methodology, Facility, Damage and Action Codes.

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1.15 PAL Nuts – Remedy for Loose or Missing Tower Bolts

1.15.1 General

An evaluation after a Type HVD 500 kV tower failed due to missing bolts determined the optimum locking device to use on tower bolts. Though a properly center-punched tower bolt will prevent a nut from backing off, it is difficult to determine when a standard bolt has been properly center-punched. Using a PAL nut over the standard tower nut to prevent the tower nut from backing off due to vibration is the preferred method.

1.15.2 Required Action

Install PAL nuts at the discretion of the supervisor when a tower has a history of loose or missing bolts, or at critical tower locations where the failure of the structure could have serious consequences.

Field experience has shown that PAL nuts are easier to install with a ratchet-type box-end wrench to prevent the wrench catching on the underlying standard nut. Install PAL nuts with the flat side toward the standard nut.

This requirement applies to towers of all voltages.

The code numbers for PAL nuts are as follows:

- 190774 for use with 1/2” bolts
- 190775 for use with 5/8” bolts
- 190776 for use with 3/4” bolts

1.16 Equipment Replacement Notifications

1.16.1 General

If a structure, foundation, conductor, or switch is not in immediate risk of failure, but is considered to be beyond economic repair, complete an LC notification in the ET AI App showing:

- Damage Code = No Good/Out of Stdrd, Action Code = Replace

Asset strategy engineering will evaluate the facility or equipment and make the determination of when and how it should be replaced. An overall yearly review of notifications and projects are part of the annual planning process.

For FAA lighting that is not functioning properly, and repairs are impractical or uneconomic, complete an LC notification in the ET AI App with the appropriate information below.

- Facility Code = FAA Battery (Steel or Wood), Damage Code = No Good/Out of Stdrd, Action Code = Replace

OR

- Facility Code = FAA Lighting (Steel or Wood), Damage Code = Missing, Action Code = Install

OR

- Facility Code = FAA Lighting (Steel or Wood), Damage Code = No Good/Out of Stdrd, Action Code = Remove or Replace

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THEN

- Priority Code = B

1.17 Overhead Job Aid for Conductor Clearances

1.17.1 General

Perform conductor clearance checks when conducting detailed inspections. Verify that clearances meet G.O. 95 and Company design requirements. Check the clearance at the mid-span of the conductor or where the clearance is at a minimum.

The minimum clearances shown in Table 9. Minimum Conductor-to-Ground Clearance Calculations and Table 10. Minimum Conductor-to-Conductor (Circuit-to-Circuit) Clearances, include a conductor sag buffer to account for variations in load and ambient conditions.

1.17.2 Conductor-to-Ground Clearance

Use Table 9. Minimum Conductor-to-Ground Clearance Calculations, to determine if the existing conductor- to-ground clearance meets the minimum requirements. See Engineering Drawing 064588, “Graphs for Ground Clearance Reduction Due to Ambient Air Temperature Rise for Overhead Line Conductors Light Loading Area” (Sheet 1 and Sheet 2), to help determine conductor sag for changes in ambient temperature and loading.

Conductor-to-ground clearance calculations are based upon G.O. 95 Rule 37 Table 1. If the appropriate clearance is not met, submit a corrective maintenance notification designated Priority Code E to correct the clearance infraction. To aid in evaluating the clearance problem, provide the ambient air temperature and wind condition, and the date and time the clearance measurement was taken.

If a QCR is uncertain whether current physical conductor-to-ground clearance conforms with Table 9, a measurement should be taken using one of the methods below and recorded in the Object list of the patrol.

1. Telescoping measuring disconnect tool (cleaned, tested, and date stamped)
2. Conductor Distance Meter (CDM) or Contour Range Finder

When either one of the options listed above cannot be applied, contact Land Management and arrange for land surveyors to verify field measurements or review annual LiDAR measurements.

Table 9. Minimum Conductor-to-Ground Clearance Calculations

Voltage	60, 70, 115 kV	60, 70, 115 kV (over railroad)	230 kV	230 kV (over railroad)	500 kV	500 kV (over railroad)
Minimum Clearance Requirement	30 feet [1]	34 feet [1]	30 feet [1]	34 feet [1]	35 feet [1]	39 feet [1]

Notes:

(1) If the measured conductor to ground clearance is less than shown on this table, consult transmission line engineering to determine the optimal conductor-to-ground clearance for the location in question and whether remediation is required.

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(2) Clearances must be measured at the low point in the span. Across uneven terrain, this might not be at the mid-span. See Figure 1. Clearance Checks on Uneven Terrain.

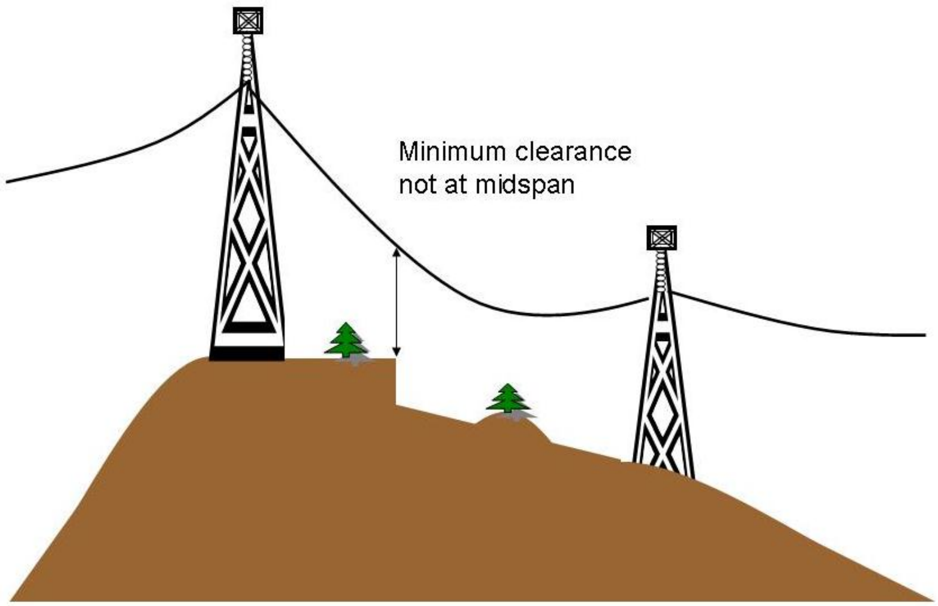

Figure 1. Clearance Checks on Uneven Terrain

1.17.3 Conductor-to-Conductor (Circuit-to-Circuit) Clearances

Use Table 10. Minimum Conductor-to-Conductor (Circuit-to-Circuit) Clearances, to determine conductor-to-conductor (circuit-to-circuit) clearances for transmission circuits with distribution underbuilt. For circuits attached on the same structure, measure clearances at mid-span, not at the support structure.

If there is a distribution pole interset under the transmission circuit, measure the circuit-to-circuit clearances at the location of the interset pole.

When less than the prescribed separation is suspected, verification of circuit-to-circuit separation as depicted in Table 10. , will require one of the same techniques listed in 1.17.2 to accurately measure and record non-compliance of circuit-to-circuit separation.

If circuit-to-circuit distance is less than described in Table 10, create a corrective maintenance notification with a Priority B (3 Month Tag).

NOTE: It is the SAP gatekeeper's responsibility to determine if the work can be completed in the 3 month time frame," based on risk factors, location, or the need for engineering solutions that might require changing the impaired clearance into a 1 year notification.

Table 10. Minimum Conductor-to-Conductor (Circuit-to-Circuit) Clearances

Voltage	60/70 kV	115 kV (Wood)	115 kV (Non Wood)
Minimum Separation for Circuits Supported on Same Structure	48 inches	84 inches	120 inches
Minimum Separation to Distribution on an Interset Pole	96 inches	120 inches	120 inches

1.18 Overhead Job Aid for Automatic Guy Strain Deadends and Splices

1.18.1 General

Guy wires are primarily installed to support mechanical strength in dead-ends, angles and spans where tensions run higher than adjacent spans. This connector can be subject to various types of exposure, such as dampness or soil disturbance due to construction or agriculture activities. Inspect and replace when necessary by means of utilizing a U-shape guy preform. Existing guy wire splices must be capable of supporting the intended strains.

1.18.2 Required Action

During detailed inspections, the QCR will inspect all guy wire assemblies, looking for any indication which may suggest the guy splice or automatic guy deadend has internal deterioration occurring per TD-06537B-001, "Automatic Guy Strand Dead Ends and Splices Supporting Transmission Facilities". Create notifications to replace or repair deadends and splices.

- Coastal environment; visual indications of deterioration, Priority B, 3 months.
- All other areas; visual indications of deterioration, Priority E, 12 months.

Conditions driving preventive maintenance for an automatic deadend/splice installed in support of transmission facilities include the following:

- Loss of galvanizing on guy wire
- Internal corrosion "bleeding" down the guy wire
- External contact with supporting structure (car/pole)
- Any visible cracking or splitting in the body of the splice or automatic deadend
- Any visible markings indicating the gripping action is slipping outward (jaw marks)
- Visible outer body has lost its protective coating (rust occurring)
- Outer body has visible port holes located at the center of the splice and shows signs of contaminants embedded within the inner body.

If in doubt of whether the splice can support the intended strains, replace or repair regardless of the visual condition if warranted.

1.18.3 Acceptable Repair/Reinforcement Options

Two reinforcement options for guy assemblies are currently allowable. Inspect the existing guy assembly to ensure all other components are in an acceptable condition and will not pose a hazard during either option for reinforcement.

1.18.3.1 Option 1

- Take two guy preforms sized for the existing wire size.
- Straighten-out by reshaping to appear as armor rod.
- Position the area of the preformed armor rod which is not formed over the guy splice and wrap both above and below the splice
- Apply the second set in the same manner as the first set.

Note: Care should be taken to minimize any slack over the splice.

1.18.3.2 Option 2

- Utilize the appropriate size hoist and grips. Leave adequate space between the grips to install one guy strain insulator and two guy preforms.
- After taking the strain, thus relaxing the guy splice, cut-out the suspect guy splice, THEN, install preforms and guy strain insulator. Utilize existing work practices for this application.
- Once installed, shunt-out the guy strain insulator by applying a short piece of guy wire to connect the ends by means of a U-bolt guy clamp, thereby creating a shunt by-passing the guy insulator.

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2. Inspections

These inspection procedures are a key element of the preventive maintenance program. The recommended actions reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified abnormal components and correcting circumstances that negatively impact safety, reliability, or asset life.

2.1 Detailed Overhead Inspections

Inspected facilities include overhead assets, rights-of-way, fiber-optic facilities, and vegetation. The overhead inspections include an external visual evaluation of the overhead facilities. See Section 5. Maintenance Procedures, for requirements that are part of the Company's overall maintenance program and are in addition to the visual inspection items identified in this section

A detailed ground, aerial, or climbing inspection of the asset looks for abnormalities or circumstances that will negatively impact safety, reliability, or asset life. Individual elements and components are examined carefully through visual and/or routine diagnostic tests, and each abnormal condition is graded and/or recorded.

Inspect overhead line facilities in accordance with the provisions in Section 1. General Inspection and Patrol Procedures. The inspections include detailed visual observations and physical testing as needed (wood pole hammer/bore test, guy tension, etc.) to identify abnormalities or circumstances that will negatively impact safety, reliability, or asset life. When performing the required visual inspection and hammer test on a wood pole, it might be determined that pole should be further evaluated by a bore test.

2.1.1 Procedures

The primary responsibility of a QCR performing an overhead facility inspection is to examine the facilities and record any abnormal conditions. This inspection requires an extensive evaluation (e.g., visual observation, which could include using measuring devices or tools) to detect any abnormal structural problems or hazards that will adversely impact safety, service reliability, or asset life, and to evaluate when each identified abnormal condition warrants maintenance.

Inspections require viewing all sides of the facilities (including line equipment). Evaluating line equipment requires a visual inspection of:

- disconnect switches
- control cabinets
- switch platforms
- lightning arrestors, etc.

FAA obstruction lighting must be reviewed for obvious defects (e.g., damaged, misaligned, dirt/debris on solar panels) and must be verified operational. Abnormal conditions that will adversely impact safety, service reliability, or asset life, and are identified by the inspector as requiring maintenance before the next inspection cycle, must be graded based on the inspector's observation and judgment.

The ET AI App uses the Facility, Damage and Corrective Action Codes listed in Table 3 representing the conditions to consider during overhead inspections. The list of options is not complete or all-inclusive.

QCRs must be thoroughly familiar with all of the standards, safety rules, and procedures associated with the facilities and equipment.

To complete repairs during the inspection, the inspector must be equipped with the appropriate safety equipment, tools, and materials. (See 8.Appendix B: Equipment, Tools, and Materials for a reference list of these items.) Guidance on the extent of repairs to be completed during inspections is provided in Section 1.5.1 Resolving Abnormal Conditions during Patrol or Inspection.

2.1.2 Substituting Aerial Inspections for Ground Inspections

It may not always be possible to perform ground inspections of lines or line sections due to access restrictions.

Using an aerial inspection to replace a ground inspection must be authorized by the transmission line superintendent on a case-by-case basis. If an air inspection is performed, the next detailed inspection must be a ground inspection.

Exception: If the original condition that prevented a detailed ground inspection still exists, a detailed aerial inspection is performed, but the QCR must be accompanied by the transmission line supervisor.

In addition, the reason for the aerial inspection must be recorded and kept on file as part of the inspection record.

2.1.3 Overhead Inspection Frequency

Inspect overhead transmission facilities per Table 11. Overhead Inspection Frequencies. Establish schedules such that inspection frequencies meet the SAP maintenance dates.

The schedules indicated in Table 11. do not preclude assigning a more frequent inspection cycle to a circuit when warranted by sound business reasons. However, increasing inspection frequency requires appropriate justification and approval by the transmission line superintendent or designee. Inspections on less frequent cycles than those listed in Table 11. are not allowed.

For circuits composed of both steel and wood structures, the inspection frequency is based on the cycle for the majority structure type (i.e., for a circuit with 51% or more steel structures, the inspection frequency is every 5 years). Light-duty steel poles are considered steel structures for these circuits. The transmission line maintenance supervisor may modify the inspection frequency to 2 years**,** based on local knowledge and exposure of the circuit.

Infrared inspections may be performed in conjunction with overhead inspections, but **must not** be considered as, or substituted for, an overhead inspection.

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Table 11. Overhead Inspection Frequencies

Voltage (kV)	Inspection Type	Structure Type	Inspection Frequency (years)
500	Detailed inspection (ground)	Steel	3
	* Climbing	Steel (non-critical)	12 (and as triggered)
	* Climbing	Steel (critical)	3 (and as triggered)
	Infrared	Steel	5 (and as triggered)
230	Detailed inspection (ground or aerial)	Steel	5
	Detailed climbing or aerial lift	Steel	As triggered
	Bay Waters Foundation Inspection	Steel	5
	Detailed inspection (ground or aerial)	Wood	2
	Climbing or aerial lift	Wood	As triggered
	Infrared	Steel or Wood	5 (and as triggered)
115	Detailed inspection (ground or aerial)	Steel	5
	Detailed climbing or aerial lift	Steel	As triggered
	Bay Waters Foundation Inspection	Steel	5
	Detailed inspection (ground or aerial)	Wood	2
	Climbing or aerial lift	Wood	As triggered
	Infrared	Steel or Wood	5 (and as triggered)
60/70	Detailed inspection (ground or aerial)	Steel	5
	Detailed climbing or aerial lift	Steel	As triggered
	Bay Waters Foundation Inspection	Steel	5
	Detailed inspection (ground or aerial)	Wood	2
	Climbing or aerial lift	Wood	As triggered
	Infrared	Steel or Wood	5 (and as triggered)

* **Note:** Detailed 500 KV climbing inspections must include information about guy tensions.

Triggers are specific conditions that require follow-up inspections and/or maintenance scheduled by the supervisor, independent of the routine schedule.

The following triggers can be applied to one unit of inspection or many units, either grouped or spread over a line section/area:

- Component defects identified by inspection
- Component failure (including failure in like components)
- Components proven defective by testing
- Wire/structure strike
- Burned area or high fire hazard
- Failures caused by natural disaster or storm
- Third-party observations and complaints
- Observed third-party development or construction conflict
- Marginal capability components of a re-rated line section
- Known, recurring conditions that jeopardize line integrity
- Suspected vegetation clearances or concerns about fast growth of vegetation

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2.1.4 Inspection Documentation

ETPM forms TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," and TD-1001M-F05, "Object List - Typical" provide adequate, consistent, and auditable inspection records, and must be used to document the inspection.

The inspection documentation process, as described below, is the responsibility of the transmission supervisor, QCR, and the clerk.

1. Before starting an inspection, the QCR must obtain the following documents for the inspection area:
    - TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical,"
    - TD-1001M-F05, "Object List - Typical"
    - An SAP report of all open notifications for the lines to be inspected, with enough information provided to understand the nature of the problems.
2. Field reviews must be performed on any pending (open) notifications to address the following issues:
    - Did the condition of the facilities deteriorate faster than expected?
    - Has the work already been completed?
    - Is the required completion date still appropriate?
3. Use the ETPM Form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," to document any new abnormalities and minor or incidental work corrected at the time of inspection. Document the required information to support the creation of individual notifications detailing each abnormality as it was identified during the inspection. For work requiring engineering and/or estimating, attaching a copy of the inspection map to the request is recommended. If FAA obstruction lighting is damaged or inoperable, refer to TD-1001P-03, "Obstruction Lighting Failure Notification Process" for procedure on notifying Federal Aviation Administration (FAA).
4. The applicable transmission line maintenance supervisor (or relief) must review and initial the QCR's inspection logs.
    - The clerk will input the notification into SAP as a staged notification and must record the corresponding notification number for each entry in the appropriate column on the ETPM Form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," .
    - The applicable transmission line maintenance supervisor will review for approval and release the staged SAP notifications.
5. Inspection information must be entered into the SAP database and reviewed for approval and release the staged SAP notifications as soon as practical (not to exceed 20 business days from the end of the inspection and before January 31 of the following year). This ensures that SAP notifications will be established in time to facilitate the proper planning, scheduling, and work to correct abnormal conditions by the due dates.
6. If a piece of equipment has been identified as damaged or inoperative, the transmission supervisor or designee must notify the GCC of the equipment condition.
    - GCC personnel enter the equipment into the Transmission Operations Tracking & Logging (TOTL).and assign a Critical Operating Equipment (COE) personal identification number (PIN).

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- The QCR must add the COE PIN to the notification's short text field in SAP and notify the GCC of the notification number associated with the PIN.

Inspection/patrol logs and notification forms are listed in 8.Appendix C: Links to Forms and Flowcharts and are available in the Technical Information Library on the Company Intranet.

2.2 Climbing Inspections (Overhead)

A climbing inspection is a detailed, supporting-structure-based observation of the facilities installed to determine if there are any abnormal or hazardous conditions that adversely impact safety, service reliability, or asset life, and to evaluate when each identified abnormal condition warrants maintenance.

Perform routine, time-based 500 kV climbing inspections, focusing primarily on structural components, on all 500 kV structures, in accordance with the inspection frequencies listed in Section 2.1.3 Overhead Inspection Frequency. Climbing inspections extend from the ground line to the top of the tower. In addition to the documentation and recordkeeping requirements associated with other routine inspections, forward the results of 500 kV climbing inspections to the Transmission Tower Davis Headquarters for record retention.

Climbing inspections also might be required for specific structures or components to assess a condition that could not be adequately assessed when identified during a ground or aerial inspection or patrol. Such conditions trigger a follow-up inspection to assign the proper Priority Code. In some cases, this requires a climbing inspection.

See Section 0 All non-routine patrols will be completed under a **Priority B – 3 Month tag**. This will allow for sufficient timekeeping, receipt of miscellaneous charges (e.g., helicopter, natural causes (fire, snow)) and collection of all necessary paperwork to complete the tag.

Overhead Non-Routine Patrol for triggers that might require a follow-up climbing inspection, and **Error! Reference source not found.**Table 2, Inspection Best-View Position, for the best vantage points for inspections of specific items.

All inspection forms must be reviewed by the local tower supervisor or designee prior to being filed as specified on TD-1001M-F03, "500kV Climbing Inspection Form and Tower Diagrams" and TD-1001M-F04, "Steel Structure Detailed Climbing Inspection (Non-500kV Structures)". TD1001M-JA02, "Detailed Climbing Inspection Job Aid" and TD-1001M-JA04, "Identifying Levels of Corrosion and Foundation Condition on Transmission Line Structures and Supports" should be referenced for additional instructions to complete the forms.

2.3 Underground Inspections

2.3.1 Underground Inspection Frequencies

See Table 12. Underground Inspection Frequencies for the underground inspection frequencies. Use the underground transmission inspection sheets and forms TD-1001M-F06 through TD-1001M-F11, depending on the inspection performed, to document test results and any abnormal conditions encountered in the field.

2.3.1.1 Detailed Inspection Frequencies

- XLPE - Perform detailed inspections once every 2 calendar years in accordance with Section 2.3.2 Detailed Inspections for XLPE Circuits.
- Pipe-type cable – Perform detailed inspections annually in accordance with Section 2.3.3 Detailed Inspections for Pipe-Type Circuits.

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- Submarine cable - Perform detailed inspections once every calendar year for the first 5 years of service in accordance with Section 2.3.2 Detailed Inspections for XLPE Circuits. After 5 years, adjust to every 2 calendar years if warranted.
- Land portion of the submarine cable – Perform same detailed inspection as for XLPE cable.

2.3.1.2 Routine Inspection Frequencies

- XLPE - Perform routine inspections every 3 months in accordance with Section 2.3.4 Routine Inspections for XLPE Circuits.
- Pipe-type cable – Perform routine inspections once each month in accordance with Section 2.3.5 Routine Inspections for Pipe-Type Circuits.
- Submarine cable - Perform routine inspections every 3 months in accordance with Section 2.3.4 Routine Inspections for XLPE Circuits.
- Land portion of the submarine cable – Perform same routine inspection as for XLPE cable.

2.3.1.3 Infrared (IR) Inspection

Perform IR inspections of underground riser terminations once every 2 years in accordance with Section 2.4.2 Infrared (IR) Inspections - Underground.

Table 12. Underground Inspection Frequencies

Voltage (kv)	Inspection Type	Cable Type	Inspection Frequency (years)
All	Detailed	Pipe-type	Once every calendar year
	Detailed	XLPE	Once every 2 calendar years
	Routine	Pipe-type	Once each month
	Routine	XLPE	Once every 3 months
	Infrared	Pipe-type	Every 2 calendar years on riser terminations
	Infrared	XLPE	Every 2 calendar years on riser terminations
	Detailed	Submarine	Once every for first 5 years, then adjust to every 2 calendar years, if warranted
	Routine	Submarine	Once every 3 months
	Marine Monitoring	Submarine	Various (under development)

2.3.1.4 Substitution of Inspections

- It is permissible to substitute a detailed inspection of XLPE or pipe-type cable circuits for a routine inspection.
- It is **not** permissible to substitute routine inspections of either XLPE or pipe-type cable circuits for detailed inspections.
- It is **not** permissible to substitute an infrared inspection for either a detailed or routine inspection. It is also **not** permissible to substitute a detailed or routine inspection for an infrared inspection.

2.3.2 Detailed Inspections for XLPE Circuits

Perform detailed inspections on XLPE circuits and components as described below.

If a component is found to be suspect during an inspection, take proper action to correct the problem, assign a specific date to correct the problem, or follow up with additional inspections or testing of suspect components according to the established Priority Codes.

Note: The QCR must fill out a notification with the inspection form.

Detailed inspections include, but are not limited to, the following items:

- Cable racking - Inspect for corrosion or breakage.
- Cable clamps - Inspect for corrosion, breakage or looseness.
- Foundations - Inspect for failing, deteriorating, or damaged concrete.
- Grounds - Inspect for loose, missing, or broken connections.
- Link boxes - Inspect for deterioration, damage, missing bonding or ground wires. If suspect Sheath Voltage Limiters (SVLs) (i.e., conductor temperature increase of cable section), open box and test SVLs.
- Hardware - Inspect for broken or deteriorating components.
- Manholes and vaults - Inspect for failing, deteriorating, or damaged concrete; water leaks; cracked and/or damaged manhole covers; and deteriorating or damaged circuit markings.
- Splice covering - Inspect for damage and deterioration.
- Terminals - Inspect for oil or gas leaks, broken porcelain skirts, and insulator coating. Inspect coatings for discoloration, peeling, contamination, and aging.
- Structures - Inspect for missing, deteriorating, or damaged circuit markings or steel members, deteriorating protective coating, and missing or loose bolts. For concrete footings, inspect for failing, deteriorating, or damaged concrete.
- Communication cables - Inspect communication cables (hard wire or fiber) for damage where present in transmission manholes
- Rights-of-way - Inspect for encroachments and installation of other facilities that might have been installed without proper authority and that interfere with clear and passable access to the terminal structures and manholes.
- Access roads - Inspect access roads for damage or erosion.

2.3.3 Detailed Inspections for Pipe-Type Circuits

Perform detailed inspections on pipe-type circuits and components as described below.

If a component is found to be suspect during an inspection, take proper action to correct the problem, assign a specific date to correct the problem, or follow up with additional inspections or testing of suspect components according to the established Priority Codes.

Note: The QCR must fill out a notification with the inspection form.

Detailed inspections include, but are not limited to, the following items:

- Ducts and pipes - Inspect for damage to pipe coatings in manholes and terminal risers, corrosion of exposed metallic pipes, and system leaks.

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- Pipe-to-soil readings at manholes and terminal risers – For pipe-to-soil readings below 0.850 V, note and contact a transmission engineer and/or transmission specialist. Also, refer to the TD-2355M, "Electric Maintenance and Construction Manual".
- Pumping plants - Test and/or calibrate plant alarms, pump plant controls, relief valves, and/or other components per the manufacturer's recommendations. Perform trip checks. Inspect for oil leaks. Contain leaks and/or repair them. If a leak is contained but cannot be repaired at the time, schedule it for repair. Refer to the pumping plant manufacturer's operation manual. Follow Inspection Procedures TD-1001P-06 "Electric Underground Transmission Pump Plant Inspections for San Mateo-Martin 230kV High Pressure Fluid-Filled (HPFF)", TD-1001P-07 "Electric Underground Transmission Pump Plant Inspections for HZ-1 and HZ-2 230kV, and High Pressure, Fluid Filled (HPFF)", TD-1001P-08 "Electric Underground Transmission Pump Plant Inspections for Figarden Tap #1 and #2 230kV (HPFF)", TD-1001P-09 "Fulton-Lakeville #1A and #1B (Oakmont) Pump Plant Test Procedures". Documents for Geyser #9-Lakeville #2 are under development.
- Cable pressures - Calibrate and/or test alarms and pressure switches. Oil-filled cable pressures can vary from line to line. Refer to the manufacturer's operation manual. For gas-filled cables, low-low pressure alarms and trip switches typically are set at 140 psig. The low alarm is set at 185 psig.
- Isolation surge protectors (ISP) - Use pre-packaged diagnostic software to test all units. (The reference voltage should be 0.5 V to 2.25 V.)
- Foundations - Inspect for failing, deteriorating, or damaged concrete.
- Grounds - Inspect for loose, missing, or broken connections.
- Hardware - Inspect for broken or deteriorating components.
- Manholes and vaults - Inspect for failing, deteriorating, or damaged concrete; water leaks; cracked and/or damaged manhole covers; and deteriorating or damaged circuit markings.
- Splice casings - Inspect for oil or gas leaks, and the condition of cathodic protection coating.
- Terminals - Inspect for oil or gas leaks, broken porcelain skirts, and insulator coating. Inspect coatings for discoloration, peeling, contamination, and aging.
- Structures - Inspect for missing, deteriorating, or damaged circuit markings or steel members, deteriorating protective coating, and missing or loose bolts. For concrete footings, inspect for failing, deteriorating, or damaged concrete.
- Communication cables - Inspect communication cables (hard wire or fiber) for damage where present in transmission manholes.
- Rights-of-way - Inspect for encroachments and installation of other facilities that might have been installed without proper authority and that interfere with clear and passable access to the terminal structures and manholes.
- Access roads - Inspect access roads for damage or erosion.

2.3.4 Routine Inspections for XLPE Circuits

Perform routine inspections and operational readings on XLPE circuits and components as described below.

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If, during the inspection, a component is found to be suspect, take proper action to correct the problem or assign a specific date to correct the problem according to the established Priority Codes.

Note: The QCR must fill out a notification form with the inspection form.

- Terminals - Inspect for oil leaks, broken porcelain skirts, and damaged insulator coating. Inspect insulator and insulator coating for discoloration, peeling, and simple aging. Check for leaks at terminals. Contain the leaks and/or repair them. If a leak is contained but cannot be repaired at the time, schedule repairs as soon as possible.
- Structures - Inspect for missing, deteriorating, or damaged circuit markings or steel members, deteriorating protective coating, and missing or loose bolts. For concrete footings, inspect for failing, deteriorating, or damaged concrete.
- Rights-of-way - Inspect for encroachments and installation of other facilities that might have been installed without proper authority and that interfere with clear and passable access to the terminal structures and manholes.
- Access roads - Inspect access roads for damage or erosion.

2.3.5 Routine Inspections for Pipe-Type Circuits

Perform routine inspections and operational readings once a month for all underground pipe-type transmission circuits and components listed below.

If during the inspection, a component is found to be suspect, take proper action to correct the problem or assign a specific date to correct the problem according to the established Priority Codes.

Note: The QCR must fill out a notification form with the inspection form.

Routine inspections include, but are not limited to, the following items:

- Terminals - Inspect for oil or gas leaks, broken porcelain skirts, and damaged insulator coating. Inspect insulator and insulator coating for discoloration, peeling and aging. Check for leaks at terminals and pressure cabinet instruments. Contain the leaks and/or repair them. If a leak is contained but cannot be repaired at the time, schedule repairs as soon as possible.
- Pumping plants - Inspect for oil leaks. Contain the leaks and/or repair them. If a leak is contained but cannot be repaired at the time, schedule repairs as soon as possible.
- Fluid or gas leaks - Check for leaks at terminals and pressure cabinet instruments. Contain the leaks and/or repair them. If a leak is contained but cannot be repaired at the time, schedule repairs as soon as possible.
- Isolator surge protector (ISP) - Check the red indicator light (red light indicates unit malfunction) and the reference voltage. (The reference voltage should be 0.5 V to 2.5 V.)
- Rectifiers - Inspect for direct current (dc) output. On circuits with rectifiers, the dc output can vary, depending on the line being protected. If there is no dc output, check for alternating current (ac) voltage or a blown fuse.
- Rights-of-way - Inspect for encroachments and installation of other facilities that might have been installed without proper authority and that interfere with clear and passable access to the terminal structures and manholes.
- Access roads - Inspect access roads for damage or erosion.

Record operational readings for the following items:

- Pumping plant oil and nitrogen pressures - Oil pressures can vary from line to line. Refer to the manufacturer's operations manual. Maintain the nitrogen pressure between 3 and 10 psig.
- Pumping plant oil volumes - Oil volume can vary from line to line. Refer to the manufacturer's operations manual for proper volumes.
- Cable nitrogen and oil pressures - Maintain gas at desirable pressures between 195 and 225 psig, not to exceed 250 psig. Oil pressures can vary from line to line. Refer to the manufacturer's operations manual for correct pressures.
- Cathodic protection reference voltages - The reference voltage should be 0.5 V to 2.5 V.

2.3.6 Detailed Inspections for Submarine Circuits

Submarine circuits are comprised of three interconnected, but different, subcomponents: subsea cable laid under water, transition point manholes, and land-based XLPE-cabling. This section pertains to detailed inspection of the underwater portion and transition points.

If a component is found to be suspect during an inspection, take proper action to correct the problem, or follow the corrective maintenance notification creation process and assign a specific date to correct the problem.

Detailed inspections include, but are not limited to, the following items:

Subsea Portion – Submarine cabling is not subject to detailed physical inspections on a recurring basis. Real-time monitoring of submarine cable performance is provided via a Distributed Temperature Sensing (DTS) system station near the terminals.

- DTS – Record temperatures and cable ratings as shown on the display. If DTS unit is inoperable, arrange for repair by vendor.
- Cable alignment – Periodic survey of submarine cable alignments to record any movement of cables. Periodic diver inspections of cables at transition bore exits (cable landings) and locations of abnormalities as indicated by alignment surveys.

In Transition Point Manholes:

- Cable racking - Inspect for corrosion or breakage.
- Racking anodes - Inspect for depletion and loss of connections
- Cable clamps - Inspect for corrosion, breakage or looseness.
- Foundations - Inspect for failing, deteriorating, or damaged concrete.
- Grounds - Inspect for loose, missing, or broken connections.
- Link boxes - Inspect for deterioration, damage, missing bonding or ground wires. If suspect SVLs (i.e., conductor temperature increase of cable section), open box and test SVLs.
- Hardware - Inspect for broken or deteriorating components.
- Manholes structure - Inspect for failing, deteriorating, or damaged concrete; water leaks from link seals; cracked and/or damaged manhole covers; and deteriorating or damaged circuit markings.
- Transition splice - Inspect for damage, deterioration or movement out of position.
- Submarine cable anchors - Inspect for missing, deteriorating, or damaged cable armor, deteriorating anchor racking and anchor bolts.

- Rights-of-way - Inspect for encroachments and installation of other facilities that might have been installed without proper authority and that interfere with clear and passable access to the terminal structures and manholes.
- Access roads - Inspect access roads for damage or erosion.

Land Cable Portion - See Section 2.3.2 Detailed Inspections for XLPE Circuits. Land cable items inside of transition vaults (i.e., racking grounds and link boxes) should be inspected at the same time as the submarine cable inspection.

2.3.7 Routine Inspections for Submarine Circuits

Perform routine inspections and operational readings on submarine circuits and components as described below.

If a component is found to be suspect during an inspection, take proper action to correct the problem, or follow the corrective maintenance notification creation process and assign a specific date to correct the problem.

Subsea Portion – Submarine cabling is not subject to routine physical inspections on a recurring basis. Real-time monitoring of submarine cable performance is provided via a DTS system station near the terminals.

- DTS – Record temperature and cable ratings as shown on the display. If DTS unit is inoperable, arrange for repair by vendor.

Land Cable Portion - See Section 2.3.4 Routine Inspections for XLPE Circuits. Land cable items inside of transition vaults should be inspected at the same time as the submarine cable inspection.

2.4 Infrared (IR) Inspections

IR inspection is an effective tool in a preventive maintenance program. IR inspection reduces the potential for component failures and facility damage and facilitates a proactive approach to identifying abnormal components for repair/or replacement. See Section 4. Infrared (IR) Inspection Procedures, for the procedures and requirements.

2.4.1 Overhead

IR inspections are performed as required per TD-1004P-04, "Conductor Rerate Process for Overhead Transmission Circuits" or as triggered.

Typically, infrared inspections are performed on overhead transmission circuits on a 5 year cycle, with approximately 20% of the lines scheduled for an infrared inspection each year. However, for circuits with critical operational impact, maintenance plans must include periodic IR inspections, if recommended by the local transmission line maintenance supervisor. Local transmission line maintenance supervisors should also consider adding lines to the annual summer readiness IR patrol in their area for conditions such as listed below:

- High concentration of bolted connectors on dissimilar conductors (copper to aluminum).
- Line averages 1 sleeve failure every 3 to 5 years.

- Radial line where previous splices/sleeves have been replaced as normal maintenance with signs of deterioration.
- Line has experienced at least 2 or more tree contacts annually (high fault current), which could have caused stresses on sleeves/connectors.
- Type of terrain and vegetation on the path of the line circuit.
- Age of line exceeds (70+ years) with original insulators, mechanical connectors, and hot end hardware showing signs of deterioration.

2.4.2 Underground

Perform IR inspections on underground transmission circuits once every 2 years. See Section 4. Infrared (IR) Inspection Procedures, for IR inspection procedures and requirements.

3. Patrols

Patrol procedures are a key element of the preventive maintenance program. The recommended actions reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified, abnormal components.

A patrol supplements the detailed facility inspection. All overhead transmission line facilities are patrolled annually. Patrol schedules are measured in terms of calendar years. A detailed facility inspection may be considered as a patrol, but a patrol cannot be considered as, or substituted for, a detailed inspection.

An overhead patrol may be performed by walking, driving, or flying (helicopter only). All patrols must be conducted in a manner that will ensure the identification of the typical problems listed in Section 3.1.1 Typical Electric Overhead Transmission Problems. Proper documentation and superintendent approval are required to substitute an air patrol for a scheduled ground patrol.

3.1 Procedures

Before performing any patrol, the QCR must obtain from the SAP database all the pending notifications for the facilities to be patrolled. This prevents duplicating maintenance notifications in SAP.

The QCR’s primary responsibility when conducting an overhead electric facility patrol is to observe the electric facilities visually, looking for obvious structural problems or hazards without using measuring devices, tools, or diagnostic tests, and to record that the facilities have been patrolled. Abnormal conditions that, in the opinion of the QCR, warrant maintenance before the next scheduled patrol or inspection, must be identified, assigned a Priority Code, and recorded. The following list gives examples of some typical problems, but is not complete or all-inclusive:

3.1.1 Typical Electric Overhead Transmission Problems

- Inadequate tree clearances
- Damaged or broken conductor
- Broken or leaning poles
- Missing or bent tower members
- Broken guys
- Broken crossarms/framing
- Broken or flashed insulators
- Inadequate conductor clearances
- Damaged line equipment
- Rights-of-way encroachments
- Bent, broken, or missing dampers
- Defective FAA obstruction lights (e.g., inoperable, damaged, misaligned) or dirt/debris on the solar panels

Assess and document any abnormal condition (other than those already documented in SAP) identified by the patrol in accordance with the requirements in Section 1. General Inspection and Patrol Procedures.

If a condition cannot be assessed properly during a patrol, a follow-up inspection must be conducted to assess the condition and assign a Priority Code.

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During the patrol, review pending notifications to:

- Confirm conditions still exist
- Determine if the work has already been completed

3.2 Patrol Documentation and Actions

Adequate, auditable records (inspection/patrol datasheets) must be kept to document all the facilities patrolled. Maintain the inspection/patrol datasheets in the same manner as specified for detailed inspections. Use SAP to schedule and track all patrols before the year they will be performed.

The patrol documentation process, as described below, is the responsibility of the transmission supervisor, QCR, and the clerk.

Before starting a patrol, the QCR must obtain the following documents for the patrol area:

- TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical,"
- An SAP report of all open notifications for the lines to be inspected, with enough information provided to understand the nature of the problems.

3.2.1 Patrol Recordkeeping and Closeout

Use the ETPM form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet – Typical," to document any new abnormalities and minor or incidental work corrected at the time of patrol. Document the required information in the inspection/patrol log to support individual notifications created in the ET AI App, detailing each abnormality as it was identified during the patrol.

Inspection/patrol log forms are listed in 8.Appendix C: Links to Forms and Flowcharts, and are available in the Technical Information Library on the Company Intranet.

The QCR must fill out completely each required field in the inspection/patrol log heading and record each abnormality encountered during the patrol. Use inspection/patrol logs in conjunction with the notifications in the ET AI App to capture the information needed to document the necessary maintenance work or action(s).

The applicable supervisor (or a designee) must review and initial the QCR's patrol logs before the information is entered in the SAP database.

It is recommended to check the SAP database to ensure that duplicate notification data is not entered. For work requiring engineering and/or estimating, attaching a copy of the inspection map to the request is recommended.

Patrol information must be entered into the SAP database and reviewed for approval and release any SAP notifications as soon as practical (not to exceed 20 business days from the end of the patrol and before January 31 of the following year). This ensures that SAP notifications will be established in time to facilitate the proper planning, scheduling, and work to correct abnormal conditions by the due dates.

3.2.2 Reporting Inoperative Equipment

If a piece of equipment has been identified as damaged or inoperative, the supervisor or designee must notify the GCC of the equipment condition.

GCC personnel enter the equipment into the Transmission Operations Tracking & Logging (TOTL) and assign a Critical Operating Equipment (COE) personal identification number (PIN).

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The QCR must add the COE PIN to the notification's short text field in SAP and notify the GCC of the notification number associated with the PIN.

3.3 Non-Routine Patrol

All non-routine patrols will be completed under a **Priority B – 3 Month tag**. This will allow for sufficient timekeeping, receipt of miscellaneous charges (e.g., helicopter, natural causes (fire, snow)) and collection of all necessary paperwork to complete the tag.

3.3.1 Overhead Non-Routine Patrol

Specific conditions require **follow-up** inspections scheduled by the supervisor, independent of the routine schedule.

The following are examples of situations that could prompt a non-routine patrol:

- Component defects identified from a less-than-ideal vantage point.
- Component failure (failure in like components) or components proven defective by testing or documented on a Form 62-0113, "Material Problem Report" (MPR).
- Wire/structure strike.
- Burned area or high fire hazard.
- Severe or prolonged storms or flood areas
- Failures caused by natural disaster or storm.
- Third-party observations and complaints.
- Observed third-party development or construction conflict.
- Marginal capability components of a re-rated line section.
- Known, recurring conditions that jeopardize line integrity or reliability performance.
- Suspected vegetation clearances less than required, less than legal vegetation clearances, or concerns about the fast-growth of vegetation.
- For all 60kV, 70kV and 115kV momentary outages, the line will be patrolled as soon as practical, but no later than the next business day. Examples:

(a) If the momentary outage occurs on Tuesday, the line will be patrolled as soon as practical, but no later than Wednesday.

(b) If the momentary outage occurs on Friday and cannot be patrolled on that day, then the patrol will be conducted on Monday (or the next scheduled regular business day).

- For all 230kV and 500kV momentary outages, the line will be patrolled as soon as practical, but no later than the next calendar day. Examples:

(a) If a momentary outage occurs early in the morning, and responsible protection engineer confirms target information and a location, then the line will be patrolled on the same day.

(b) If the momentary outage occurs late in the afternoon or early in the evening, and it is not practical to attempt a patrol immediately due to darkness, then the line will be patrolled the next day. This requirement is in effect regardless of whether or not the next day is a regular work day.

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3.3.2 Underground Non-Routine Patrol

Specific conditions require follow-up inspections scheduled by the supervisor, independent of the routine schedule.

The following are examples of situations that could prompt a non-routine patrol:

- Component failure (like components) or components proven defective by testing
- Failures caused by natural disaster or storm
- Third-party observations and complaints
- Observed third-party development or construction conflict
- Known, recurring conditions that jeopardize line integrity or reliability performance
- Directional drilling or trenching in the vicinity of an underground transmission line not identified by Underground Service Alert (USA) locating and marking
- Encroachment of the underground easement by third parties affecting access to underground transmission line for inspection or repairs
- Public events with extremely large attendance.

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4. Infrared (IR) Inspection Procedures

IR inspection procedures are a key element of the preventive maintenance program. The recommended maintenance priorities reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified abnormal components.

Perform IR inspections when required by Utility Procedure TD-1004P-04, "Conductor Rerate Process for Overhead Transmission Circuits," or as triggered.

In addition, lines that have exceeded their emergency ratings for 30 minutes or more must be IR-inspected for possible component damage. Schedule this inspection as soon as possible or when conditions allow (line loading, weather, etc.).

It is the responsibility of the GCC to notify the local electric transmission supervisor that a condition as specified above has occurred.

Additional IR inspections might be required as triggered per Section 3.3 Non-Routine Patrol.

4.1 Detailed IR Procedures

Electric transmission system inspections and preventive maintenance programs use IR imaging and temperature-measuring systems to identify faulty components and initiate repairs or replacement proactively.

Based on industry specifications, connectors should experience lower operating temperatures than their respective conductors. This means that any time the temperature of a connector is greater than the temperature of its respective conductor, a higher-resistance connection exists and a failure can be expected, but not precisely predicted. It is probable that degradation will occur faster with an increase in load or temperature.

Conductor manufacturers recommend a usual maximum operating temperature for tensioned, bare conductor of 185°F.

Conductor manufacturers recommend the following maximum operating temperatures for insulated conductors:

- 167°F for high-molecular-weight polyethylene (HMWPE).
- 194°F for cross-linked polyethylene (XLPE).
- 194°F for ethylene-propylene rubber (EPR).

With insulated conductor systems, the temperature measured at the surface of an insulated conductor or component could be between 20% and 50% of the actual temperature of the targeted conductor or component (e.g., if the actual temperature of the component is 212ºF, the measured temperature could be between 68ºF and 122ºF, respectively).

IR imaging systems detect and record all of the heat being radiated in their fields of view. IR cameras use an image-scanning technique to identify heat radiated from a target and its background. IR imaging systems capture and store the heat images pictorially for immediate or future evaluation. By using IR imaging systems, the operator can pinpoint the precise location of the hottest spot on the target being observed.

The recommended maintenance is based on the measured operating temperature of both the target and its respective connectors or conductors, the temperature differentials between the

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target and its respective, adjacent components, or thermal image showing component hot, as well as the operational risk associated with each.

4.1.1 Equipment

Video-imaging equipment used for IR inspections must meet the following minimum specifications:

- Image storage – Equipment must have the ability to store images for future analysis
- Lens interchangeability – The IR camera must have lens interchangeability, or personnel must have access to a camera with lens interchangeability, to enable inspections at varying distance to the object to be inspected.
- Wave length – The IR system must be "Long Wave," responding to wave lengths of 8 to 14 microns.
- Camera lens – A 3x to 10x telescopic lens is required for accurate IR measurements at a safe distance.
- Palette – IR system must have color palette with unique and easily distinguishable colors for over-temperature conditions in order to locate hot spots and to verify that the image is not saturated. A gray-scale palette with a color-distinguishing minimum and maximum saturation threshold is preferred.
- Camera mount – For helicopter IR inspections, a gimbal or gyro-stabilized remote-controlled camera mount attached to the exterior of helicopter is preferred to dampen vibration.
- Calibration – IR cameras that provide temperature readings must have been factory-calibrated within 1 year before the patrol. IR cameras or systems that do not provide temperature readings do not require calibration within 1 year before the patrol. Hand held IR cameras used for **overhead only** must have been factory-calibrated within 2 years (due to the minimal use of camera).
- Recording media –The system must be capable of recording IR or color video of the entire inspection scan for special requests, along with color and IR still photos of each anomaly found.
- Audio input - For helicopter IR inspections, the system must be capable of recording audio input from the helicopter intercommunication system.

Systems used for aerial (helicopter) IR inspections by contractors must be used in accordance with the manufacturer's requirements. The equipment used for aerial IR inspections must meet all requirements above.

4.1.2 Setting Up the IR Camera

Establishing the proper IR-imaging system setup parameters for emissivity and background temperature is critical to obtaining accurate measurements with IR cameras. The other system-setup parameters are used primarily to record and assist initial or future evaluations of heat radiated from a target and its background.

Setting the emissivity value at 1.0 eliminates the need to set the background temperature. The target, in this case, is considered to be a blackbody, totally reflective and non-transmissive. With highly emissive targets, the actual reflected energy is so small with respect to the emitted energy that the temperature measurement is well within reason for predictive maintenance applications.

As the emissivity value of the target decreases, the influence of background radiation increases, and consequently, so does the potential for errors based on background temperature settings. If the emissivity value is set at less than 1.0 and the background temperature setting is adjusted inaccurately, the resulting temperature measurement of the target could have more error than it would if the emissivity value were set at 1.0.

For example, with an emissivity setting less than 1.0, if the background temperature setting is higher than the actual background temperature, the target's temperature measurement will be less than it should be. If the background temperature setting is lower than the actual background temperature, then the target's temperature measurement will be higher than it should be. The measurement deviation compounds as the emissivity setting decreases from 1.0.

Setting the emissivity value at 1.0 eliminates the need to determine exact emissivity and background temperature values, simplifies the system operation, and results in reasonably accurate measurements. For example, when IR measurements are taken on overhead systems where the ceiling (sky) is unlimited, an accurate background temperature is nearly impossible to determine. Furthermore, most targets have dark surfaces and therefore will have emittance values very close to 1.0.

4.1.3 Infrared (IR) Scanning Technique

4.1.3.1 Overhead

1. Center the targeted component in the viewer or sight of the IR scanning device and observe the temperature(s) measured.
2. Scan 1 to 2 feet of the conductor or cable entering and/or leaving the targeted image and observe the temperature(s) measured.
3. Center the respective, adjacent components in the viewer or sight of the IR scanning device and observe the temperature(s) measured.
4. Repeat Step 2 for each respective, adjacent component.
5. IF the temperature of the targeted component is greater than those listed in Table 13. Determining Maintenance Priorities, OR shows hot with IR system that does not provide temperature readings,

THEN record the information requested in Section 4.3 IR Inspection Documentation, using the TD-1001M-F15, "Transmission Line Infrared Data Sheet." Attach the datasheet to the notification created for abnormal finding.

4.1.3.2 Underground – Cable Terminals

1. Center the targeted component (terminal—composite or porcelain) in the viewer or sight of the IR scanning device and observe the temperature(s) measured. See Figure 2. Pipe-Type and XLPE Terminals.
2. Center the respective, adjacent components (terminal ferrule or aerial connector stub) in the viewer or sight of the IR scanning device and observe the temperature(s) measured.
3. Scan 1 to 2 feet of the conductor connected to the terminal ferrule or aerial connector stub and observe the temperature(s) measured.
4. Repeat Step 2 for each respective, adjacent component.

5. IF the temperature of the targeted component is greater than those listed in Table 13. Determining Maintenance Priorities, OR shows hot with IR system that does not provide temperature readings,

THEN record the information requested in Section 4.3 IR Inspection Documentation, using the TD-1001M-F15, “Transmission Line Infrared Data Sheet.” Attach the datasheet to the notification created for abnormal finding.

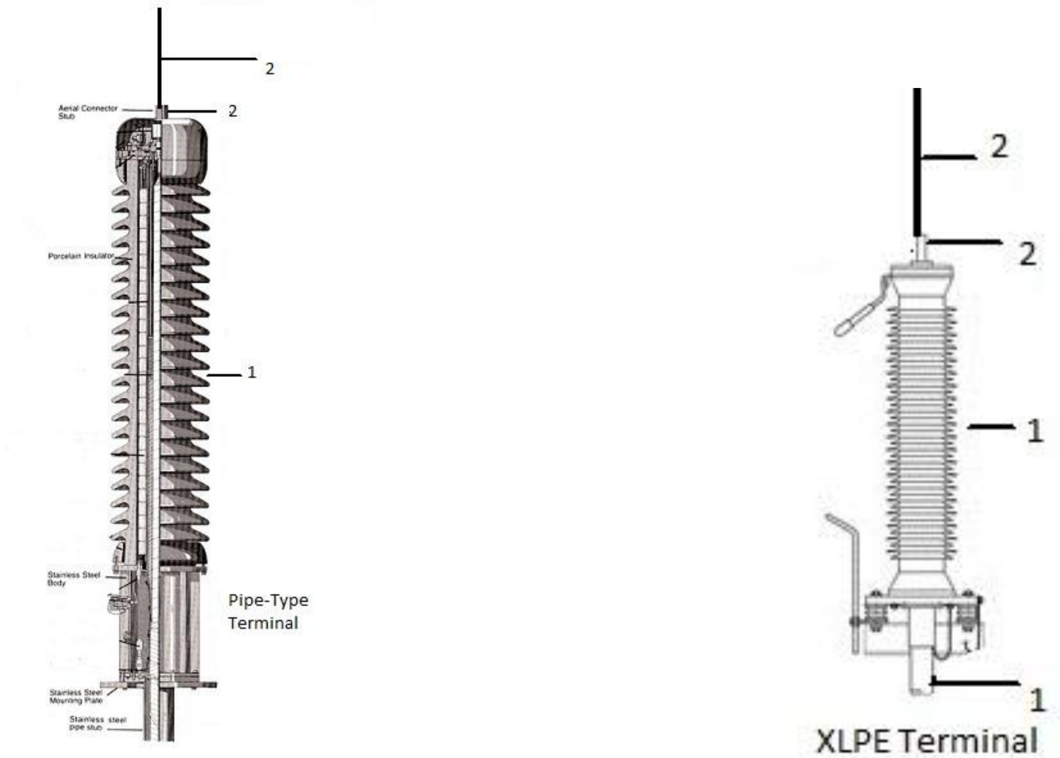

Figure 2. Pipe-Type and XLPE Terminals

4.1.4 Determining the Maintenance Priority

To assess and prioritize the relative severity of the conditions found during the IR inspection, as based on the measured temperatures and/or temperature rise, refer to Table 13. Determining Maintenance Priorities. (If IR system does not provide temperature readings, and there are no obvious visual signs of deterioration, then make a Priority B tag and complete as soon as possible.)

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4.1.5 Determining Maintenance Priorities

Table 13. Determining Maintenance Priorities

Transmission Facilities	Temperature Differential (ΔT)	Priority/Remarks
Overhead & Underground Direct heat (See Notes)	>100°F	Priority A: Notify supervisor and repair, replace, or make component safe immediately.
	25 °F to 99°F	Priority B: Repair or replace component within 3 months.
Underground Indirect heat (See Notes)	20°F and over	Notify supervisor. Contact Underground Engineering to determine mitigation

Notes:

1. If excessively high operating temperatures (>100°F) are found, or obvious physical damage is observed, immediate action must be taken (Priority A).
2. B priority tags should be given a high priority. B tags should be corrected as soon as possible, preferably within 60 days, but not to exceed a period of 3 months.
3. Underground – Upon completion of repair or replacement, perform another IR inspection to verify that the abnormal condition was corrected and is operating under normal condition.
4. Temperature taken at underground cable terminals illustrated in Figure 2. Pipe-Type and XLPE Terminals.: Location 1 is an indirect reading; Location 2 is a direct reading.

4.2 IR Inspection Requirements

It is generally necessary for lines, or segments of lines, to be loaded to 40% or greater of the operating ratings in order to perform a meaningful IR inspection. IR inspections are less likely to yield useful results if the lines are not heavily loaded. On single-source generation lines and some tap lines, loads often cannot be switched to achieve the load needed to perform a meaningful IR inspection. When practical, IR inspections should be performed on lines loaded to at least 40% of the operating ratings. An IR inspection cannot be substituted for an aerial inspection.

4.2.1 Weather Considerations

Weather conditions can have an adverse effect on IR inspection results. Do **not** perform IR inspections under the following conditions:

- Winds in excess of 25 miles per hour (mph)
- Steady rain in progress

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4.3 IR Inspection Documentation

The QCR or thermographer must document abnormal findings, record the information listed below in form TD-1001M-F15, "Transmission Line Infrared Data Sheet," and attach the form to the IR finding notification. This form is generated by SAP.

- Name of the employee performing the inspection (thermographer)
- Time and date of the inspection
- Circuit SAP number
- Identification of the "hot item" type and phase location (e.g., connector, jumper, etc.).
- Weather conditions
- Disk (or file name) and photo numbers
- Load amperes

QCRs using IR cameras with the capacity to provide temperature readings should record the following information as well:

- Background (or ambient) temperature setting
- Emissivity setting
- Fault temperature
- Reference temperature (like piece of equipment)
- Temperature rise
- Temperature-differential grade

5. Maintenance Procedures

Before scheduling clearances for maintenance work, identify all maintenance work on a transmission line by using object lists, notifications, and other sources to minimize the number of clearances required on any given circuit.

Inspectors must complete all repairs of abnormal conditions that can be done safely by an individual at the time of inspection. Section 5.1.1 Minor/Incidental Maintenance provides a guide for the types of maintenance that can be performed at the time of inspection.

5.1 Overhead

The following exhibits contain procedures and flowcharts that provide required, step-by-step processes for performing maintenance to correct abnormal conditions identified during routine inspections:

- Exhibit 1, "Notification Initiation Flowchart"
- Exhibit 2, "Notification/Completed Patrol Review"

5.1.1 Minor/Incidental Maintenance

Minor / incidental work is completed by the inspector at the time of the inspection and recorded on an ETPM form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet - Typical."

To facilitate completing repairs during the inspection, the inspector must be equipped with the appropriate safety equipment, tools, and materials to perform required maintenance.

For a list of common safety equipment, tools, and maintenance materials, refer to the tables listed in 8.Appendix B: Equipment, Tools, and Materials:

- Table 18. Safety Equipment List
- Table 19. Tool List
-
- Table 20. Materials List

5.2 Underground Job Aid for Maintenance Procedures

5.2.1 Requirements

Appropriate maintenance activity is determined based on inspection results, historical operation of the facilities, utility best practices, sound engineering, and economic judgment. Refer to Section 2. Inspections for inspection procedures.

Schedule the frequency of maintenance as stated in Section 2.3 Underground Inspections. Also, maintenance can be condition-based, triggered by specific events, or as identified during emergency, routine, and/or detailed field inspections. Conditions requiring maintenance are assigned a Priority Code on a notification, and repairs must be performed within the period determined by the Priority Code.

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5.2.2 Terminals

- For oil and gas leaks, tighten connections, replace O-rings and gaskets, and check torque values, per the manufacturer's recommendations.
- Consult with the transmission engineering group to determine corrective action for the following:
  - Broken porcelain
  - Broken standoff insulator and deteriorated riser coating
  - Loose, missing, or broken connections and grounds

5.2.3 Pumping Plants

- Calibrate and/or test alarms, Supervisory Control and Data Acquisition (SCADA), pump plant controls, relief valves, pressure switches, and/or any other component, per the manufacturer's or the transmission engineering group's recommendations.
- Repair or replace defective components to maintain fluid pressures. Consult with the supervisor to determine corrective action.

5.2.4 Manhole and Vault Integrity

- Covers – Replace broken covers.
- Circuit markings – Re-mark as needed.
- Deteriorating or damaged concrete – Consult with the transmission engineering group to determine corrective action.
- Splice casings – Replace coating as needed.
- Manholes – Repair water leaks; and replace ladders rigging eyes and racking, as needed.
- Racking – Replace corroded racking components. If protected by anodes, check for depletion of anodes and replace if needed.

5.2.5 Fluid and Gas Pressures/Alarms

- Calibrate and/or test alarms, pressure switches, and SCADA.
- Add fluid or gas to the system when pressures or storage volumes fall below the recommended normal operating levels.

5.2.6 Cathodic Protection

- Rectifiers – Replace if there is no voltage or current output.
- Pipe-to-soil – If the profile falls below 0.850 V, check the rectifier and anode output, and check the connections. Check for foreign contact in manholes or where pipes are exposed at construction sites and verify that the bypass switch is open at the polar cells/ISP cabinet.
- Replace or paint cabinets as needed. Consult with the transmission engineering group to determine corrective action.
- Repair or replace pipe-wrap in manholes and riser pipe as needed.
- Isolator surge protector (ISP) – Refer to the manufacturer's operating guidelines.

5.2.7 Valve Replacement

Repair and/or replace valve components within the period determined by the Priority Code.

5.2.8 Silicone Terminal Coating

Repair and/or replace terminal coating. Consult with the transmission engineering group to determine corrective action.

5.2.9 Anodes

Replace or add anode components if there is no current output. Consult with the transmission engineering group/PG&E corrosion engineer to determine corrective action.

5.2.10 Link Boxes

Inspect for deterioration, damage, missing bonding or ground wires. If suspect SVLs (i.e., observed conductor temperature increase of cable section), open box and test SVLs.

5.2.11 Structures

- Circuit markings – Re-mark as needed.
- Deteriorating foundations or damaged concrete – Consult with the transmission engineering group to determine corrective action.
- Damaged hardware – Consult with the transmission engineering group to determine corrective action.
- Damaged steel members – Consult with the transmission engineering group to determine corrective action.
- Protective coating – Replace as needed. Consult with the supervisor to determine corrective action.

5.2.12 Right-of-Way

Clear obstructions and consult with the transmission engineering group to determine corrective action. If there is an encroachment on the Right-of-Way, refer to Section 1.3.7, Reporting Nonconformance With Trespass or Encroachment, using the Facility Code Right of Way.

5.2.13 Access Roads

If there is an issue with the access road, address any immediate issue, such as clearing drainage obstructions. If more work is needed, refer to Section 1.3.5, Reporting Nonconformance With Access Roads and Gates, using the Facility Code Road.

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6. Enhanced Inspection and Maintenance Requirements for Diablo Canyon and Morro Bay Power Plants Overhead Transmission Facilities

The enhanced inspection and maintenance requirements contained within Section 6 apply to the 230kV and 500kV circuits listed in Table 14.

Table 14. Diablo Canyon PP and Morro Bay PP Enhanced Inspection Circuits

230kV	500kV
Morro Bay-Diablo 230kV *	Diablo Unit #1 500kV **
Morro Bay-Mesa 230kV *	Diablo Unit #2 500kV **
Diablo PP Stand-By Supply 230kV **	Diablo-Gates #1 500kV *
Diablo-Mesa 230kV *	Diablo-Midway #2 500kV *
	Diablo-Midway #3 500kV *

* Transmission Line Maintenance Supervisor, Pismo Beach responsibility
** DCPP Switchyard Supervisor responsibility

6.1 Detailed Overhead Inspection

Inspected facilities include overhead assets, rights-of-way, fiber-optic facilities, and vegetation. The overhead inspections include an external visual evaluation of the overhead facilities. See Section 5. Maintenance Procedures for requirements that are part of the Company's overall maintenance program and are in addition to the visual inspection items identified in this section

A detailed ground, aerial, or climbing inspection of the asset looks for abnormalities or circumstances that will negatively impact safety, reliability, or asset life. Individual elements and components are examined carefully through visual and/or routine diagnostic tests, and each abnormal condition is graded and/or recorded.

Inspect overhead line facilities in accordance with the provisions in Section 1. General Inspection and Patrol Procedures. The inspections include detailed visual observations and physical testing as needed (wood pole hammer/bore test, guy tension, etc.) to identify abnormalities or circumstances that will negatively impact safety, reliability, or asset life.

6.2 Overhead Inspection Frequency

Inspect overhead transmission facilities per Table 15. Overhead Inspection Frequencies-DCPP and Morro Bay PP Transmission Line Facilities. Establish schedules such that inspection frequencies meet the SAP maintenance dates.

The schedules indicated in Table 15 do not preclude assigning a more frequent inspection cycle to a circuit when warranted by sound business reasons. However, increasing inspection frequency requires appropriate justification and approval by the transmission line superintendent or designee. Inspections on less frequent cycles than those listed in Table 15 are not allowed.

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Infrared inspections may be performed in conjunction with overhead inspections, but must not be considered as, or substituted for, an overhead inspection.

Table 15. Overhead Inspection Frequencies-DCPP and Morro Bay PP Transmission Lines

Voltage (kV)	Inspection Type	Structure Type	Inspection Frequency
500	Detailed inspection (ground)	Steel	Annually
	Climbing *	Steel	3 years (and as triggered)
	Patrol **	Steel	Quarterly
	Infrared/Corona	Steel	Annually (and as triggered)
230	Detailed inspection (ground or aerial)	Steel	Annually
	Climbing or aerial lift	Steel	As triggered
	Patrol **	Steel	Quarterly
	Structure Inspection ***	Steel	3 years (and as triggered)
	Infrared/Corona	Steel	Annually (and as triggered)

* **Note:** Detailed 500 KV climbing inspections must include information about guy tensions.

**** Note:** This patrol is only performed during the quarters when a Detailed Inspection is not completed**.**

***** Note:** Structure inspections are to only be performed on DCPP Structures 0/1A and 0/1B of the Diablo PP Stand-By Supply 230kV overhead transmission line.

Triggers are specific conditions that require follow-up inspections and/or maintenance scheduled by the supervisor, independent of the routine schedule.

The following triggers can be applied to one unit of inspection or many units, either grouped or spread over a line section/area:

- Component defects identified by inspection
- Component failure (including failure in like components)
- Components proven defective by testing
- Wire/structure strike
- Burned area or high fire hazard
- Failures caused by natural disaster or storm
- Third-party observations and complaints
- Observed third-party development or construction conflict
- Marginal capability components of a re-rated line section
- Known, recurring conditions that jeopardize line integrity
- Suspected vegetation clearances less than required or less than legal vegetation clearances, or concerns about fast growth of vegetation

6.3 Climbing/Structure Inspections

A climbing inspection is a detailed, supporting-structure-based observation of the facilities installed to determine if there are any abnormal or hazardous conditions that adversely impact safety, service reliability, or asset life, and to evaluate when each identified abnormal condition warrants maintenance.

A structure inspection is a detailed ground or aerial lift based observation of the facilities installed to determine if there are any abnormal or hazardous conditions that adversely impact safety, service reliability, or asset life, and to evaluate when each identified abnormal condition warrants maintenance.

Perform routine, time-based 500 kV climbing inspections, focusing primarily on structural components, on all 500 kV structures, in accordance with the inspection frequencies listed in Section 6.2 Overhead Inspection Frequency. Climbing inspections extend from the ground line to the top of the tower. In addition to the documentation and recordkeeping requirements associated with other routine inspections, forward the results of 500 kV climbing inspections to the Transmission Tower Davis Headquarters for record retention.

Climbing inspections also might be required for specific structures or components to assess a condition that could not be adequately assessed when identified during a ground or aerial inspection or patrol. Such conditions trigger a follow-up inspection to assign the proper Priority Code. In some cases, this requires a climbing inspection.

See Section 3.3.1 Overhead Non-Routine Patrol, for triggers that might require a follow-up climbing inspection, and Section 1. General Inspection and Patrol Procedures, Table 2, Inspection Best-View Position for the best vantage points for inspections of specific items.

Perform routine, time-based 230kV structure inspections; focusing primarily on structural components, on the specified 230kV structures, in accordance with the inspection frequencies listed in Section 6.2 Overhead Inspection Frequency. In addition to the documentation and recordkeeping requirements associated with other routine inspections, forward the results of 230 kV structure inspections to the Transmission Tower Davis Headquarters for record retention.

All inspection forms must be reviewed by the local tower supervisor or designee prior to being filed as specified on TD-1001M-F03, "500kV Climbing Inspection Form and Tower Diagrams" and TD-1001M-F04, "Steel Structure Detailed Climbing Inspection (Non-500kV Structures)". TD1001M-JA02, "Detailed Climbing Inspection Job Aid" and TD-1001M-JA04, "Identifying Levels of Corrosion and Foundation Condition on Transmission Line Structures and Supports" should be referenced for additional instructions to complete the forms.

6.4 Patrols

Overhead patrol procedures are a key element of the preventive maintenance program. The recommended actions reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified, abnormal components.
A "patrol" supplements the detailed facility inspection. Patrol frequencies on those facilities listed in Table 14 shall be in accordance with the schedule listed in Table 15. A detailed facility inspection may be considered as a patrol, but a patrol cannot be considered as, or substituted for, a detailed inspection.

An overhead patrol may be performed by walking, driving, or flying (helicopter only). All patrols must be conducted in a manner that will ensure the identification of the typical problems listed in Section 3.1.1 Typical Electric Overhead Transmission Problems. Proper documentation and superintendent approval are required to substitute an air patrol for a scheduled ground patrol.

6.5 Infrared (IR)/Corona Inspections

IR and corona inspection are effective tools in a preventive maintenance program. IR and corona inspection reduces the potential for component failures and facility damage and facilitates a proactive approach to identifying abnormal components for repair/or replacement. See Section 4. Infrared (IR) Inspection Procedures, for the procedures and requirements.

Infrared and corona inspections on DCPP and Morro Bay PP 500kV and 230kV transmission line facilities listed in Table 14 are performed on a specified schedule as listed in Table 15, due to their critical operational impact. Maintenance plans for the listed circuits must include periodic IR and corona inspections at intervals listed in Table 15.

6.6 Dirty/Contaminated Insulator Cleaning

Perform insulator washing based on local environmental conditions, operating experience, and the predetermined wash cycles established in SAP. Wash insulators in accordance with the TD-1257M, "Insulator Cleaning Manual", Section 3, "Program." Maintenance plans must be created in SAP for the circuits (or portions of circuits) listed in Table 14 that require quarterly insulator washing.

For the Diablo PP Stand-By Supply 230kV circuit, de-energized insulator washing will be performed during scheduled plant outages. For all other circuits in Table 14, hot washing of insulators will be performed on a quarterly basis for structures within one mile of DCPP and for structures within two miles of Morro Bay PP. It may be possible to defer a scheduled wash for these facilities to coordinate with scheduled plant outages. These deferrals would only be considered for a specific exception, and not on a routine basis. If a deferral is requested, the facilities should be assessed for contamination levels. Use Equivalent Salt Deposit Density (ESDD) samples to assess the amount of contamination.

The supervisor responsible for the circuits will decide if a schedule wash should be considered for deferral. The supervisor will arrange for the wipe samples to be taken and sent to ATS for processing. ATS will process the wipe samples and send the results to the requesting supervisor and save the results in the ATS records. The contamination grade listed in Table 16. ESDD Contamination Grades will be used to determine the ability to defer a scheduled wash. The supervisor will review the results and, if necessary, make a recommendation (including the ESDD results) via EDRS for approval of the deferral. For circuits that are under the DCPP responsibility, the Transmission Line Maintenance and Construction Director will concur and the DCPP Switchyard Supervisor will approve in EDRS based on the results of the DCPP PM deferral process. For circuits that are under the transmission line responsibility, the DCPP Switchyard Supervisor will concur and the Transmission Line Maintenance and Construction Director will approve in EDRS. As noted in Table 16, the maximum deferral will be 90 days.

Table 16. ESDD Contamination Grades

Contamination Grade*	ESDD (mg/cm^2)	Washing Schedule
Light	0.03 – 0.08	Wash may be deferred to scheduled outage, not to exceed 90 days without an additional wipe test
Medium	0.08 – 0.25	Wash may be deferred, but not more than 60 days without an additional wipe test
Heavy	0.25 – 0.60	Wash may not be deferred
Extra Heavy	> 0.60	Wash must be done immediately

* From IEEE C57.19.100-2012

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7. Document Governance

7.1 Document Approver(s)

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7.2 Document Owner(s)

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8. Revision Notes

Document Location	Date of Change	Change Log
Change Log	05/2017	Added change log.
Entire Document	05/2017	Minor revisions and change to verbiage.
Section 1.3.4 – Reporting DO nonconformance	05/2017	Added reference to October 2015 5MM with additional process details and link to said document. Added language clarifying bridging as Distribution work funded through the GRC rate case as communicated in 04/2016 bulletin 'TD-1001B-001 Transmission Bridging Tag Creation and Completion'.
Section 1.6.1 – Inspection/Patrol Records	05/2017	Updated verbiage to reflect 07/2016 bulletin 'TD-1001B-002 Inspection/Patrol Records and Deadlines' clarifying timing of paperwork handoff between QCR and clerical.
Section 1.7; Table 6 – Guide for Assigning Priority Codes	05/2017	Updated verbiage to reflect 08/2016 bulletin 'TD-1001B-003 Foundations Priority Code F' clarifying allowance of priority code F (24 months) for foundation repair work, especially in sensitive environmental areas where typical permitting and project timelines are significantly longer.
Section 1.5.3 & 1.5.3.1	05/2017	Modified Section 1.5.3 – Notifications Extending Beyond Due Dates and added Section 1.5.3.1 – LC Past Due Exemption Process outlining the requirements of the past due exemption process and referencing the job aid with full details (TD-1001M-JA03). This change incorporates 04/2017 bulletin 'TD-1001B-004 – LC Past Due Exemption Process'.
Section 1.1 – Record Keeping	05/2017	Updated verbiage to reflect 01/2017 bulletin 'TD-1001B-005 Electronic Signature' clarifying that PG&E single sign-on electronic devices can be used as signatures for all purposes formerly requiring wet paper signature (e.g., email, SAP gatekeeper).
Section 1.1.2 – Records Retention Requirements	05/2017	Added a note on legal holds & provided notice that as of publishing date Electric Operations is still under a legal hold for all records.
Entire Document	09/2018	Minor revisions, updated FDA codes, updated links, updated table numbers and change to verbiage.
Section 1.3.3 Reporting Vegetation Nonconformance	09/2018	Added NERC/CAISO critical lines and updated section per Vegetation Management
Sections 1.3.5 through 1.3.7	09/2018	Updated sections per Land Operations and added more specific information on encroachment
Section 1.4 OH Methodology, Facility, Damage and Action Codes	09/2018	Updated section to reflect ET AI App and new codes for overhead and underground. Deleted cause codes
Section 1.5	09/2018	Added and Due Dates to the title

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Document Location	Date of Change	Change Log
Section 1.5.1 Resolving Abnormal Conditions during Patrol or Inspection	09/2018	Updated method for charging maintenance tasks > 15 minutes and how to capture on the time card
Section 1.5.2	09/2018	Noted Director approval for Priority Code F and added information on High Fire Threat Districts
Section 1.5.3.2	09/2018	Added new section on approval of past due notifications
Section 1.6 Creating and Closing Inspection/Patrol and Maintenance Records	09/2018	Updated based on electronic work and timelines
Table 6	09/2018	Updates from experts throughout table for Priority Codes. Added to Note regarding Pole Test and Treat reference.
Section 1.8.1 Insulator Strength and Loading	09/2018	Added information on suspension type porcelain insulators
Section 1.11.3	09/2018	Added section on OPGW and ADSS cable to focus on during patrols inspection
Section 1.16 Equipment Replacement Notifications	09/2018	Updated to reflect no LR notifications through the LC notification and how asset strategy reviews notifications for equipment replacement. Also updated FAA notifications to reflect Priority B
Section 2.1.1 Procedures	09/2018	Updated to reflect ET AI App instead of form F02
Section 2.2 Climbing Inspections	09/2018	Clarified non-routine patrols are Priority B
Section 2.3.3 Detailed Inspections for Pipe-Type Circuit	09/2018	Added Fulton-Lakeville #1A and #1B (Oakmont) Pump Plant Test Procedures
Section 2.3.6	09/2018	Added updates for roads and right-of-ways
Section 2.3.7 Routine Inspection for Submarine Circuits	09/2018	Removed Transition Manhole information that is covered in other sections
Section 5.2 UG Job Aid For Maintenance Procedures	09/2018	Removed information on polarization cells and chart motors
Appendix A: Acronyms and Definition of Terms	09/2018	Removed definitions that were not used
Appendix B: Equipment, Tools, and Materials	09/2018	Updated codes
Appendix C: Links to Forms and Flowcharts	09/2018	Removed F02 since it is the ET AI App

Document Location	Date of Change	Change Log
Appendix D: Summary of Links to Related Documents	09/2018	Added new documents
Appendix E: Line Patrol File Guidelines	09/2018	Updated to reflect ET AI App and new deadlines
Appendix F: ET AI App Process Guidelines	09/2018	New
TD-1001M-F01 and TD-1001M-F12	09/2018	Removed old FDA codes
TD-1001M-F02	09/2018	Deleted
TD-1001M-F03 and TD-1001M-F04	09/2018	Replaced with updated form

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Appendix A: Acronyms and Definition of Terms

The following definitions of terminology are used in this manual.

Table 17. Acronyms and Definition of Terms

Terms	Definitions
Abnormal Condition	A condition that adversely impacts or has the potential to adversely impact safety, service reliability, or asset life.
Ambient Temperature	The prevailing temperature in the immediate vicinity of the object or target, i.e., the temperature of the target's environment.
Apparatus	Temperature (or "Fault" Temperature): The temperature of the targeted surface that the thermographer is evaluating.
Auditable Records	Documentation, written and electronic, that shows the results of an inspection (as defined in this section), the facility condition assessment, and the subsequent maintenance and/or repair activity.
Bay Waters	Saltwater environments located in the nine counties of the San Francisco Bay area.
CAISO	California Independent System Operator.
Calendar Year	January 1 through December 31 of any year. For maintenance interval purposes, for example, if a task is performed on June 17, 2009 and is on a "1 calendar year interval," the task is required to be performed again on or before December 31, 2010
Component	A specific item of a unit of inspection, e.g., structure, terminal, right-of-way, pumping plant, manhole, insulator, etc.
Corrective Maintenance	Maintenance activities that restore facilities that have failed or contributed to an unacceptable operation condition, typically following an unusual and unforeseen incident. These may include inspection, assessment, repair, and replacement activities associated with restoring the facility.
Critical 500 kV Towers	The 2% most critical 500 kilovolt (kV) towers, as identified in the Pacific Gas and Electric Company (Company) "500 kV Emergency Restoration Study" (1993), based upon an equal weighting of the "susceptibility to failure" and "benchmark restoration time" factors.
Decayed Wood	Wood that has lost its strength due to insect infestation or decomposition caused by fungi.
Electric Transmission Asset	Rights-of-way (R/Ws), fee property, fences, buildings, conductors, structures, and associated hardware and equipment that operate at voltages above 50,000 volts (V).
Emergency Patrol	A patrol performed as a result of a momentary or sustained outage caused by an unknown condition on an overhead or underground transmission line. It is a visual check made either by ground or air to look for the specific condition that caused the outage. An emergency patrol must not be considered as, or substituted for, an inspection of electric transmission facilities.
Emissivity	The relative ability of a surface to emit heat by radiation. Emissivity is the ratio of the heat emitted by a surface compared to that emitted by a blackbody.
Emittance Value	The ratio of the intensity of thermal radiation, at a given wavelength or spectral waveband, from a target to the thermal radiation emitted by a blackbody of the same temperature as the target.

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Terms	Definitions
Field of View	The size of the scene surrounding the target, as observed by the infrared scanner and expressed as the ratio between the size of the scene surrounding the target and the distance between the target and the scanner.
Hot Item	An apparatus, device, or equipment found to have excessive apparatus ("fault") temperature.
Identified Maintenance Condition	Abnormal conditions that require corrective action before the next inspection cycle.
Infrared (IR) Inspection	A diagnostic test using IR thermography technology to identify abnormal conditions.
Infrared (IR) Radiation	IR radiation (or energy) is a part of the electromagnetic spectrum lying outside of the visible spectrum on the red end. Visible light and IR have similar behavior; the main difference is wavelength. IR has a wavelength between 2 and 1,000 micrometers. Visible light has a wavelength of between 0.4 and 0.75 micrometers.
Inspection/Patrol Datasheet or Form	A datasheet or form used to document the inspection and/or patrol of a facility, and to identify abnormalities that require corrective action or follow-up inspection; for example, the ETPM form TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet - Typical," and the underground inspection datasheets shown in the ETPM forms: TD-1001M-F06, "Monthly Pipe-Type Routine Inspection - Typical" and TD-1001M-F07, "Detailed Pipe-Type Inspection – Typical."
Inspection	A detailed ground, aerial, or climbing observation of the asset installed, looking for abnormalities or circumstances that will negatively impact safety, reliability, or asset life. Individual elements and components are examined carefully through visual and/or routine diagnostic tests, and the abnormal conditions of each are graded and/or recorded.
Interval	A specified, maximum time period between inspections of overhead and underground electric transmission facilities.
Line Section	A group of structures and conductor, terminal-to-terminal, excluding line breakers and associated disconnect switches.
Long Wave	The portion of the electromagnetic spectrum that ranges from 8 to 14 microns.
Maintenance	Preventive or corrective actions to ensure the safety and reliability of electric transmission facilities. It includes capital and expense expenditures for tasks associated with the inspection, repair, refurbishment, and possible replacement of existing electric transmission facilities to ensure safe and reliable operation.
Material Problem Report (MPR)	A report written to document damage resulting from faulty materials or workmanship, impacts from sources other than the asset or its intended use, sabotage, criminal acts, negligence, etc.
Micron	A unit of length equal to one millionth of a meter, which is used to describe the wavelength of infrared radiation. "Micron" is the popular name for "micrometer."
Minor/Incidental Work	Work that can safely be accomplished at the site by a QCR during a detailed and/or routine inspection.
Missing	Used to describe a component that is required, but not present. It is not intended to describe components that are not required to be present (i.e., dampers or high-voltage signs that are not required are not considered to be "missing").
Notification	A document identifying an abnormality that requires corrective action, follow-up inspection, or referral to other departments or entities. Notifications generated in the field by QCRs at the time the abnormal condition is observed must be entered into the Systems Application and Products in Data Processing (SAP) program.

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Terms	Definitions
Notification Form	A recorded document identifying a specific facility condition that requires corrective action, follow-up inspection, or referral to other departments or entities. These forms are part of the ET Asset Inspection (AI) App.
Object List	An SAP-generated form that lists (by circuit) structure numbers, SAP equipment numbers, structure framing and description; Geographic Information System (GIS) coordinates, and access information. The object list is used as a daily inspection log and to verify overhead assets. The "Note" section is used for recording access information only.
PAM	Pole Asset Management.
Patrol	A brief, visual inspection of applicable utility facilities (equipment and structures) that is designed to identify obvious structural problems and hazards. Patrols may be carried out in the course of other Company business, provided certain requirements are met. An emergency patrol, which is usually precipitated by an unusual system incident, must not be considered as, or substituted for, a regularly scheduled inspection or patrol of electric transmission line facilities.
Preventive Maintenance (PM)	Activities that ensure facilities and their associated components will continue to perform within accepted parameters. These activities may include inspection, assessment, maintenance, and replacement activities that occur before an abnormal condition exists.
Qualified Company Representative (QCR)	A Company representative, who, by knowledge, required training, and/or work experience, is able and allowed to perform a specific job. For the purposes of this manual, QCR refers to an employee qualified to prepare an accurate and complete assessment of electric transmission facilities.
Radiate	To emit. When an object radiates, it emits or sends out electromagnetic waves.
Reference Temperature	The temperature of a like piece of equipment at the same location as that registering the apparatus ("fault") temperature.
Reflective	The ability of a target to reflect or send back rays. A mirror has a reflective surface with respect to visible light.
Reflectivity (also known as reflectance)	The amount of radiation that is reflected from a surface. Reflected radiation is not absorbed or transmitted. The reflectivity of a surface equals 1 - (emittance + transmittance).
Reinforcement	Mechanical technique(s) that restores the strength of a wood pole, decayed at or near the ground line, to serviceable condition.
Restoration	Mechanical techniques(s) that restores the shell or the heart of a wood pole, decayed or damaged above the ground line, to serviceable condition.
SAP	Systems Application and Products in Data Processing. An information system used to record, schedule, and manage work activities such as inspection maintenance.
Stub	Usually a short length of steel truss or wood pole, driven or set into the ground and attached to the existing pole by suitable and adequate fastenings. A stub provides the support originally afforded by the pole butt.
Subject Pole	A pole that is "non-exempt" per the *Power Line Fire Prevention Field Guide*.
System	One or more line section(s) that perform the same defined function.
Temperature Rise (or Temperature Differential)	The difference in temperature between the apparatus ("fault") temperature and the reference temperature.
Testing	A method or process used to conduct an examination or trial to obtain a positive indicator, along with recording data from the event.
Thermographer	A person who performs an IR inspection to obtain information concerning a target, object, structure, system, or process.
Thermography	Any photographic, videotaped, computer-generated, or graphic record of information derived from an IR inspection.
Transmission Control Agreement (TCA)	An inspection and maintenance agreement filed with the CAISO that outlines the Company's Electric Transmission Inspection and Maintenance Program.

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Terms	Definitions
Transmission Facilities	Conductors, structures, and/or associated equipment that are constructed to transport electric power of 50,000 V and above, from one point to another.
Transmissive	The ability of a medium to allow electromagnetic radiation to pass through it without being reflected or absorbed (to send or transmit rays from one point to another). Glass is highly transmissive to visual light.
Transmissivity (also known as transmittance)	The amount of radiation that is transmitted through a surface. Transmitted radiation is not reflected or absorbed. The transmissivity of a surface equals 1 - (emittance + reflectance).
Trigger (Non-Routine Patrol)	A condition that may require follow-up inspection and/or maintenance of facilities at a frequency different than the intervals determined by line prioritization or condition assessment.
Underground Transmission Facilities	Any conductors and associated equipment that are constructed at or below ground level for the purpose of transporting electric power of 50,000 V and above, from one point to another.
Unit of Inspection	A portion of a line section identified as a structure and its “ahead” span.
Vegetation Management (VM)	The inspection, trimming, and removal of trees and brush within the vicinity of electric facilities to ensure safe and reliable transmission service. The acronym VM also is used to refer to the Company’s Vegetation Management Department.

Appendix B: Equipment, Tools, and Materials

The tables below list items an employee or QCR may need to perform inspections and minor maintenance activities. The tables are intended as a reference resource and include safety equipment to ensure worker and public safety, and tools and materials that enable inspectors to perform minor/incidental maintenance work. The material codes are listed to assist with procuring these items when establishing the contents of vehicles used during the inspection process.

Table 18. Safety Equipment List

Description	Information Source	Code
Barricade Frame, Manhole	*Code of Safe Practices*, Section 7, Rule 708	M205092
Barrier Tape, 3 Inches Wide	*Work Area Protection Guide* (623151)	E620421
Cones, Traffic, 18 Inches High	*Work Area Protection Guide* (623151)	E206240
Cones, Traffic, 28 Inches High	*Work Area Protection Guide* (623151)	M206391
Flag, Red	*Work Area Protection Guide* (623151)	E202416
Hard Hat, Cap Style	*Code of Safe Practices*, Section 1, Rule 3	E207761
Hard Hat, Standard Style	*Code of Safe Practices*, Section 1, Rule 3	M206153
Safety Glasses, Black Frame	*Code of Safe Practices*, Section 1, Rule 17	Various
Stand, for Sign and Flag	*Work Area Protection Guide* (623151)	E030512
Vest, Traffic, Size Large	*Work Area Protection Guide* (623151)	RHPVF-3091E-L
Vest, Traffic, Size X Large	*Work Area Protection Guide* (623151)	RHPVF-3091E-XL

Note: "M"-coded items indicate PG&E Material Codes; "E"-coded items are purchased thru Ariba.

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Table 19. Tool List

Description	Code	Description	Code
Air Monitor, Personal	M231805	Kit, First Aid	E622724
Binoculars	231088	Knife, Dexter	E200632
Bit, 9/16-Inch x 18-Inch, Shaper Auger	E200038	Knife, Putty, 1¼-Inch	E200510
Blades, for Hacksaw	M200886	Ladder, 10-Foot	M203122
Broom, House	M209004	Line, Hand	NA
Brush, Wire	M209013	Manhole Lifting Tool	E202439
Case, Carrying, for Extension Stick	M205548	Meter, Volt, Fluke #77	M244287
Chasers, Thread, Set ¼-Inch to 1-Inch	E205794	Pigtail, With Pulling Eye	M205447
Computers, Hammerhead With GPS/GIS	NA	Pin, Clothes, Clamp, Plastic	E206187
Cutters, Bolt, 18-Inch Handles	E202974	Press, MD6	NA
Cutters, Cable, HK Ptr. #8690	Various	Press, XMJ, Nicopress #53	M201009
Cutters, Cable, T&B #364	M201553	Pump, Water, Hand	M202565
Die, WBG	M202848	Rope, Hot, ½-Inch Diameter, 100-Foot	E102020
Die, W249	M203039	Saw, Chain, 14-Inch (Optional)	210603
Drill, Hand, Brace	NA	Saw, Hack	M201110
Drill, Rechargeable, ½-Inch Drive	NA	Saw, Tree, Hand, Fanno #7	E200986
Driver, Screw, 6-Inch, Philips	NA	Saw, Tree, With Pruner	E201946
Driver, Screw, 6-Inch, Standard	M200598	Scabbard, for Fanno #7 Saw	M200987
Driver, Screw, 10-Inch, Standard	M200600	Shears, Pruning	NA
Extinguisher, Indian Backpack	E481006	Shotgun, 6-Foot	M205395
Eye, Guy-Pulling	M201114	Shovel, Flat	M200609
Flashlight Rechargeable Mag.	M200306	Shovel, Round	M200608
Fault-Indicator Reset Tool	M202248	Socket, Penthead	M202233
Gun, Caulking	NA	Stick, SL Catalog #2596, 1¼-Inch Diameter, 8-Foot	M205565
Gun, Infrared, 3M	NA	Tape, Measuring, 100-Foot	E201877
Hammer, Claw, 22-Ounce	M200432	Tool, Combination, for Pad-Mounted Equipment	M208094
Hardhat Light	E204958	Weed Eater	NA
Hook, Manhole, Flexible Type	E200479	Switch Lock, 2 ¼ inch long shank SEECO	M170030
Hook, Manhole, Ridged Type	E200480	New Switch Locks	TBD
Hook, Switch Fuse, With QC	M205668	-	-

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Table 20. Materials List

Description	Code	Description	Code
Bolt, Penthead, ⅜-Inch x 1¼-Inch	192831	Nut, With Spring, ½-Inch, 13 NC Thread (P1010) (Old Penthead Cast in Frame)	580143
Bolt, Penthead, ⅜-Inch x 2-Inch	192896	Nut, With Spring, ½-Inch, 13 NC Thread (P4010) (Horizontal With Wood Enclosure)	580152
Bolt, Penthead, ½-Inch x 1-Inch	192081	Paint, for Pad-Mounted Equipment, Green, Aerosol Can	130458
Bolt, Penthead, ½-Inch x 1¾-Inch	192832	Paint, Zinc Rich Primer for Pad-Mounted equipment, Aerosol Can	130479
Bolt, Penthead, ½-Inch x 2-Inch	NA	Plug, Set Screw, Bus Bar, CMC	019683
Bolt, Penthead, ½-Inch x 2½-Inch	192853	Plug, Set Screw, Bus Bar, Homac	019684
Bolt, Penthead, ½-Inch x 3½-Inch	017488	Plug, Wooden Dowel, ⅝-Inch	NA
Bolt, Penthead, ½-Inch x 4½-Inch	017489	Screw, 5/16-Inch, Allen, Flat Head, SS, ½-Inch x ¾-Inch (# Plate Holders)	193391
Bolt, Penthead, Coil Thread, ½-Inch x 1¾-Inch	190068	Splice, Auto Guy, 7/32-Inch	186150
Bolt, Penthead, Coil Thread, ½-Inch x 2-7/16-Inch	031412	Splice, Auto Guy, 5/16-Inch	186128
Caulking, Sealant	495228	Splice, Auto Guy, ⅜-Inch	186129
Ground Molding, Plastic U-Shape, 1½-Inch Diameter	360008	Splice, Auto Guy, 7/16-Inch	186130
Ground Molding, PVC Conduit, ½-Inch Diameter	360368	Tag, High Voltage/Clearance Label for Pad-Mounted Equipment	621599
Guy Guard, Cattle	186186	Tag, High Voltage/PG&E Nameplate for Underground Enclosures	015543
Guy Marker, Plastic	186045	Tags, Phase and Voltage	See Note
Guy Marker, Steel	186176	Tag, High Voltage/Clearance Label for Pad-Mounted Equipment	621599
Guy, Preform, 7/32-Inch	186149	Tags, Red Plastic, Write-On	031811
Guy, Preform, 5/16-Inch	186118	Tags, Yellow Plastic, Write-On	031809
Guy, Preform, ⅜-Inch	186119	Visibility Strip, Barrier Post	374440
Lock, Corporation	016583	Visibility Strip, Guy	373278
Lock, Equipment Safety, 1-Inch	170115	Visibility Strip, Pole	373271
Lock, Equipment Safety, 2-Inch	170116	Wire, Six-Strand, Copper, Hand Coil	290072
Molding, Hardwood	149005	Wire, Four-Strand, Copper, Hand Coil	NA
Nut, With Spring, ⅜-Inch, 16 NC Thread (Old Penthead Cast in Frame)	580142	Wire, Two-Strand, Copper, Hand Coil	NA
Nut, With Spring, ½-Inch, 13 NC Thread (AS-100) (Covers Before 1986)	580211	-	-

Note: See Numbered Document 033582, "Tags for Identifying Underground Cables and Equipment," Table 1.

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Appendix C: Links to Forms and Flowcharts

Table 21. Forms Index

Forms Index
Overhead Inspection Forms
TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet - Typical"
TD-1001M-F03, "500kV Climbing Inspection Form and Tower Diagrams"
TD-1001M-F04, "Steel Structure Detailed Climbing Inspection (Non-500kV Structures)"
TD-1001M-F05, "Object List - Typical"
TD-1001M-F16, "Pile Foundation Inspection Form"
Underground Inspection Forms
TD-1001M-F06, "Monthly Pipe-Type Routine Inspection - Typical"
TD-1001M-F07, "Detailed Pipe-Type Inspection - Typical"
TD-1001M-F08," Quarterly XLPE Routine Inspection - Typical"
TD-1001M-F09, "Detailed XLPE Inspection - Typical"
TD-1001M-F10, "Alarms/SCADA Annual Test Sheet - Typical"
TD-1001M-F11, "Electric Pumping Plant Annual Calibration Sheet - Typical"
TD-1001M-F12, "Corrective Work Form Electric Transmission Underground"
Equipment Record Forms
TD-1001M-F13, "Request to Add Equipment Records to the Asset Registry"
TD-1001M-F14, "Request to Delete Equipment Records to WM SAP"
Infrared Forms
TD-1001M-F15, "Transmission Line Infrared Data Sheet" (Excel)
Material Forms
Form 62-0113, "Material Problem Report" (MPR)
TD-1957P-01-F01, "Component Testing Information Sheet."
Flowcharts
These flowcharts illustrate typical processes for overhead electric transmission maintenance procedures: Exhibit 1, "Notification Initiation Flowchart" Exhibit 2, "Notification/Completed Patrol Review" Exhibit 4, "Transmission Vegetation Management Notifications – Steel Structure Clearing" Exhibit 5, "Transmission Vegetation Management Notifications – Wood Pole Clearing" Exhibit 6, "Transmission Vegetation Management Notifications – VM Compliance Work" Exhibit 7, "Transmission Vegetation Management Notifications – Access Work"

Appendix D: Summary of Links to Related Documents

The following table contains a summary of the links contained in this manual, with the exception of those already listed in Appendix C: Links to Forms and Flowcharts.

Table 22. Links to Related Documents

TD-1248M, "Barehand Work Procedures Manual"
Engineering Document 033582, "Tags for Identifying Underground Cables and Equipment,"
ET GIS SAP – Request for Work Job Aid – Creation
General Order (G.O.) 95, "Rules for Overhead Electric Line Construction"
General Order (G.O.) 128, "Rules for Construction of Underground Electric Supply and Communication Systems"
General Order (G.O.) 165 "Inspection Requirements for Electric Distribution and Transmission Facilities"
TD-015014B-001, "Approval Required for Installation Suspension Type Porcelain Insulators"
TD-06537B-001, "Automatic Guy Strand Dead Ends and Splices Supporting Transmission Facilities"
TD-1257M, "Insulator Cleaning Manual"
Power Line Fire Prevention Field Guide
SCM-2106P-01, "Material Problem Report Procedure."
TD1001M-JA01, "Patrol, Inspection and Closing Process"
TD1001M-JA02, "Detailed Climbing Inspection Job Aid"
TD1001M-JA03, "Transmission LC Past Due Exemption Process"
TD1001M-JA04, 'Identifying Levels of Corrosion and Foundation Condition on Transmission Line Structures and Supports"
TD-1001P-03, "Obstruction Lighting Failure Notification Process"
TD-1001P-06, "Electric Underground Transmission Pump Plant Inspections for San Mateo-Martin 230kV High Pressure Fluid-Filled (HPFF)"
TD-1001P-07, "Electric Underground Transmission Pump Plant Inspections for HZ-1 and HZ-2 230kV, High Pressure, Fluid Filled (HPFF)"
TD-1001P-08, "Electric Underground Transmission Pump Plant Inspections for Figarden Tap #1 and #2 230kV (HPFF)"
TD-1001P-09 "Fulton-Lakeville #1A and #1B (Oakmont) Pump Plant Test Procedures"
TD-1001S, "Electric Transmission Line Inspection and Preventive Maintenance Program"
TD-1003S, "Management of Idle Electric Transmission Line Facilities"
TD-1004P-04, "Conductor Rerate Process for Overhead Transmission Circuits"

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TD-1005P-03, “Evaluating Uses of Company Transmission Line Easements by Others”
TD-1005S, “Right-of-Way and Encroachments”
TD-1006P-02, “Switch Maintenance and Inspection Program for Electric Transmission”
TD-1006P-02-JA-01, “Electric Transmission Line Switch Inspection/Function Test Job Aid.”
TD-1006B-004, “Procedure for Marking Duplicate Transmission Switches”
TD-1957P-01, “Electric Transmission Line Equipment Failure Analysis Procedure”
TD-2325P-01, “Wood Poles - Testing, Reinforcing and Reusing”
TD-2325P-01-F01, “Attachment 1 - Pole Inspection/Test Report”
TD-2325S, “Wood Pole Inspection, Testing, and Maintenance”

Appendix E: Line Patrol File Guidelines

The following lists contain a summary of what should be included in the folders that are in the transmission line maintenance supervisor's office. Annually for each circuit, two folders should be created. There will be one folder for Annual Patrols and one folder for the Line Files. Print the appropriate forms and include in the specific folder for each circuit.

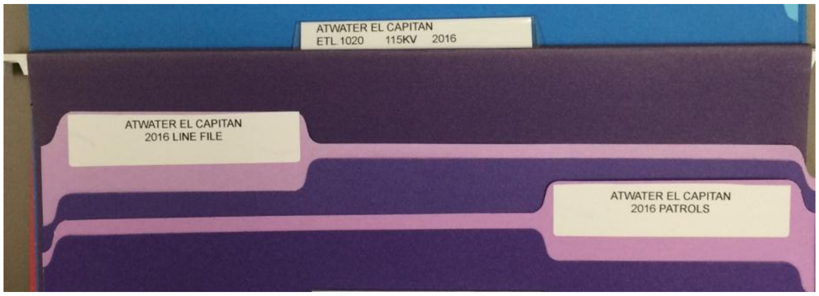

Figure 3. Line Folder Examples

<u>Folder 1- Annual Patrols (Line Name, Year, Patrols)</u>

1) Detailed Inspections
    a) Operational Control Ticket (9010)
    b) Transmission Line Inspection Datasheet (9970)
        i) Datasheets must be filled out completely. QCR must complete top of datasheet, sign and date the body of the datasheet.
        ii) One notification must be created for each finding, except for minor maintenance work (less than 15 minutes) that has been completed. The datasheets should include each finding with the notification number AND any minor maintenance completed in the field.
        iii) List on the datasheet if no findings were found.
        iv) Supervisors must sign and date.
        v) Scan completed datasheet and attach to the order.
    c) Transmission Line Object List (9971)
        i) Each page should have QCR's name and inspection date listed at the top.
        ii) Check only one box.
        iii) Include changes in directions, combination lock codes, LIDAR measurements (one location/mile with height, temperature, date and time), etc.
        iv) Any changes on the object list must be scanned and an RW created.
    d) List of existing notifications (IW28) from SAP
    e) Map of line with species (Fresno, Midway & Victor only)

2) Air and Ground Patrols
    a) Operation Control Ticket (9010)
    b) Transmission Line Inspection Datasheet (9970)
        i) Datasheet must be filled out completely. QCR must complete top of datasheet, sign and date the body of the datasheet.
        ii) One notification must be created for each finding. The datasheets should include each finding with the notification number.
        iii) List on the datasheet if no findings were found
        iv) Supervisors must sign and date.
        v) Scan completed datasheet and attach to the order.
    c) Transmission Line Object List Coversheet (9971 or 9972, either form is appropriate)
        i) For 9971:

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(1) Each page should have QCR's name and inspection date listed at the top
(2) Check only one box
(3) Include changes in directions, combination lock codes, LIDAR measurements (one location/mile with height, temperature, date and time), etc.
(4) Any changes on the object list must be scanned and a RW created

ii) For 9972:
(1) Sign and date with the structures completed, e.g., 1/1 through 20/155

d) List of existing notifications (IW28 from SAP)

Folder 2-Line File (Line Name, Year, Line File)

Within the Line File Folder, file the completed notifications and miscellaneous information.

1) Non-Routine Patrols
   a) Completed Notification must be scanned and attached to notification in SAP.

2) Completed Notifications
   a) Only print notification (computer generated SAP notification) when work completed thus including the most updated information.
   b) Completed notifications must include what work was completed, the date completed and the signature and LAN ID of the person who completed the work.
   c) Each notification should have a Construction Completion Standard Checklist (CCSC) attached. If the location has underbuild, there must be a Distribution CCSC form attached also.
   d) If notification is noted as found in field completed, then the notification should be set for deletion. If the notification is linked to a capital order, the notification should be de-linked before deleting and notify engineering to cancel the order. If the notification is linked to an expense order, notify the asset/maintenance planner to cancel the order.
   e) If the crew finds a problem at an adjacent location and corrects the problem while working a notification, then:
      i) Foreman completes the notification, signs and dates
      ii) Supervisor reviews and signs
      iii) SAP notification created electronically

THERE SHOULD BE NO PENDING FILE OR WORKING FILE IN YOUR LINE FILES.

3) Miscellaneous Information
   a) Miscellaneous Information
      i) Miscellaneous notifications should be kept to a minimum
      ii) Important information should be scanned and attached to the completed notification. Do not copy unnecessary information into the body of a notification (e.g., emails).
      iii) Information unrelated to notifications should be kept to a minimum

DO NOT COPY UNNECESSARY INFORMATION INTO THE BODY OF A NOTIFICATION i.e., EMAILS. ANYTHING NOTED ON A NOTIFICATION CAN BE VIEWED BY AUDITORS. ATTACHMENTS ARE FOR INTERNAL VIEWING.

Note--- Capital notifications should not be filed in the capital jobs or in the line files. Completed capital jobs should be filed in a completed capital file by line name also by year.

Appendix F: ET AI App Process Guidelines

The following screenshots shows the data input screens to use during inspections and patrols when notifications are created.

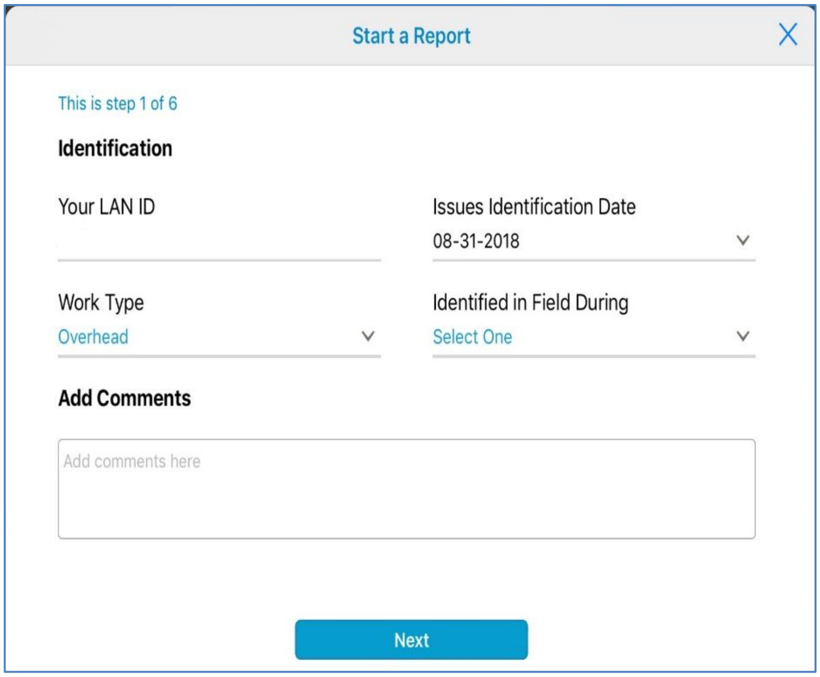

Figure 4: Start a Report

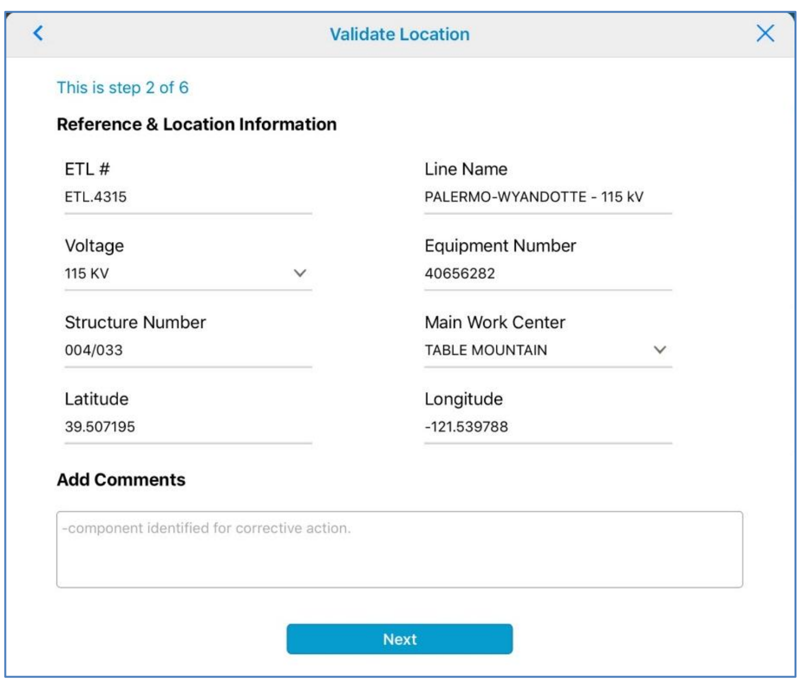

Figure 5: Validate Facility and Location

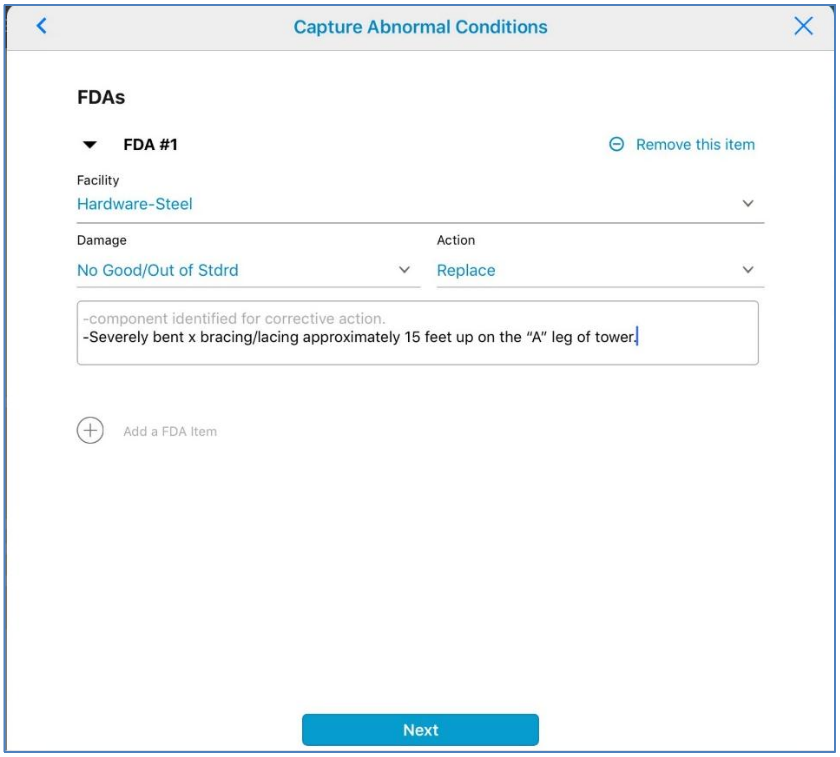

Figure 6: Choose Facility, Damage and Corrective Action

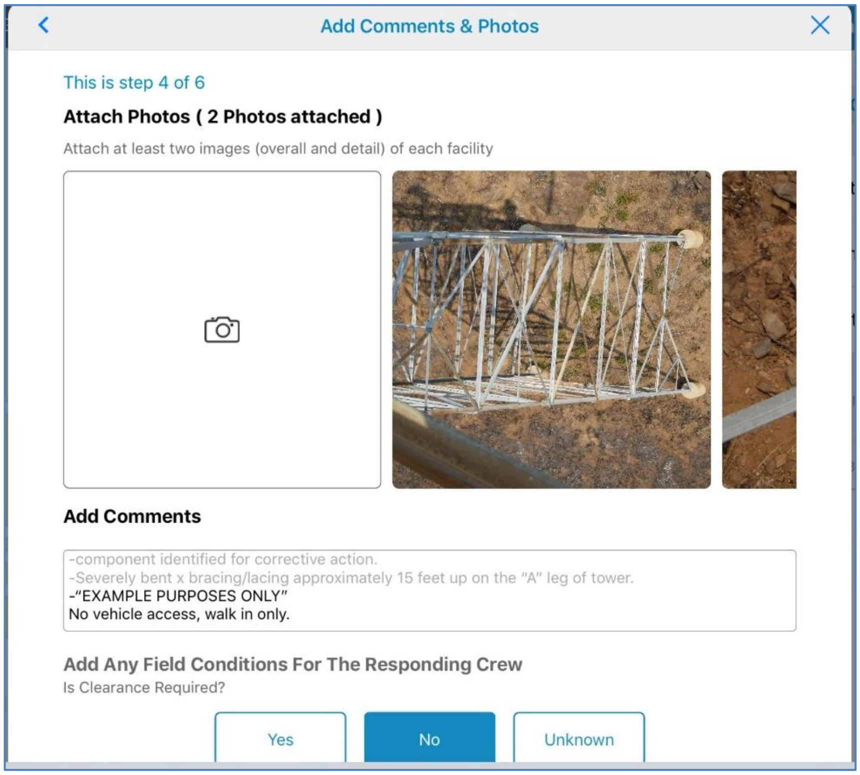

Figure 7: Attach Photo(s) and Determine if a Clearance is Required

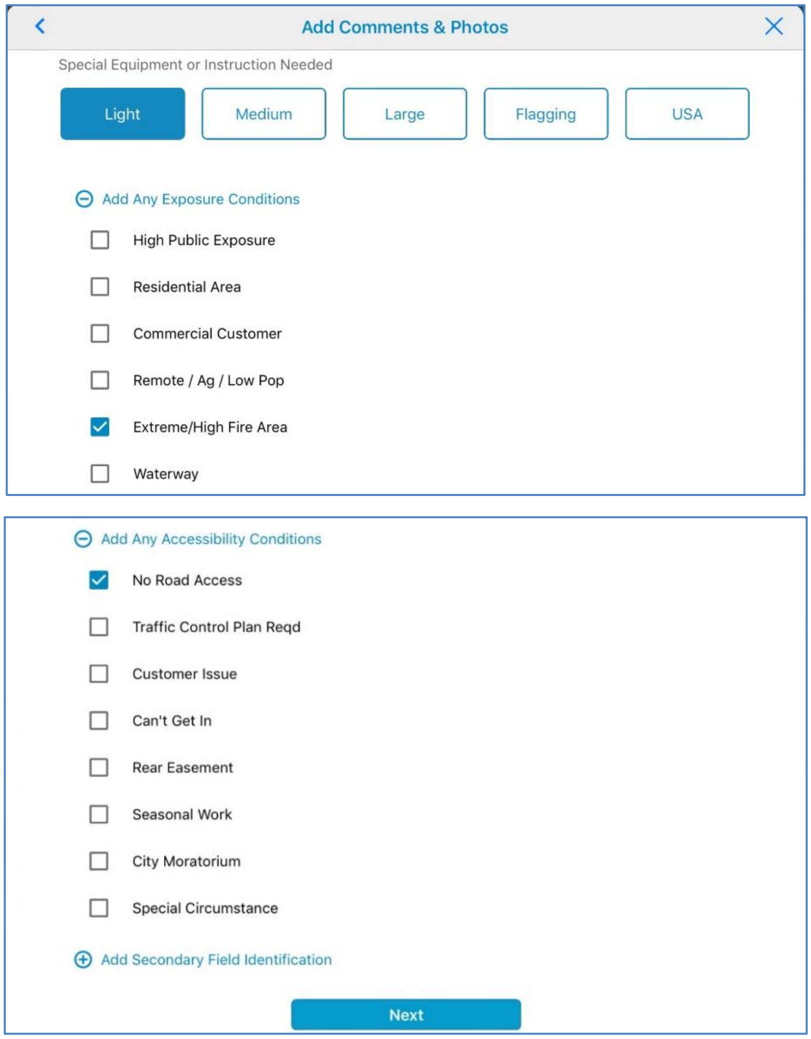

Figure 8: Describe Field Conditions

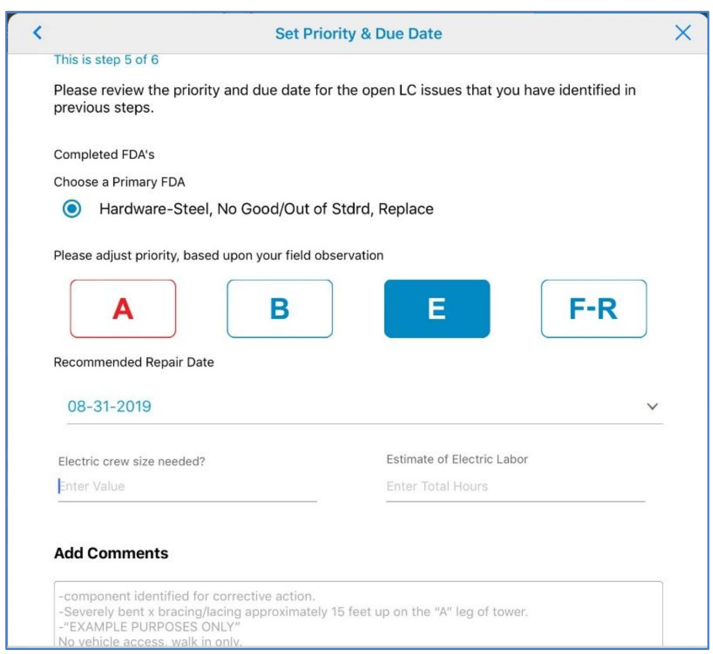

Figure 9: Set Appropriate Priority Code, Adjust Date if Necessary and Determine Crew Size and Hours

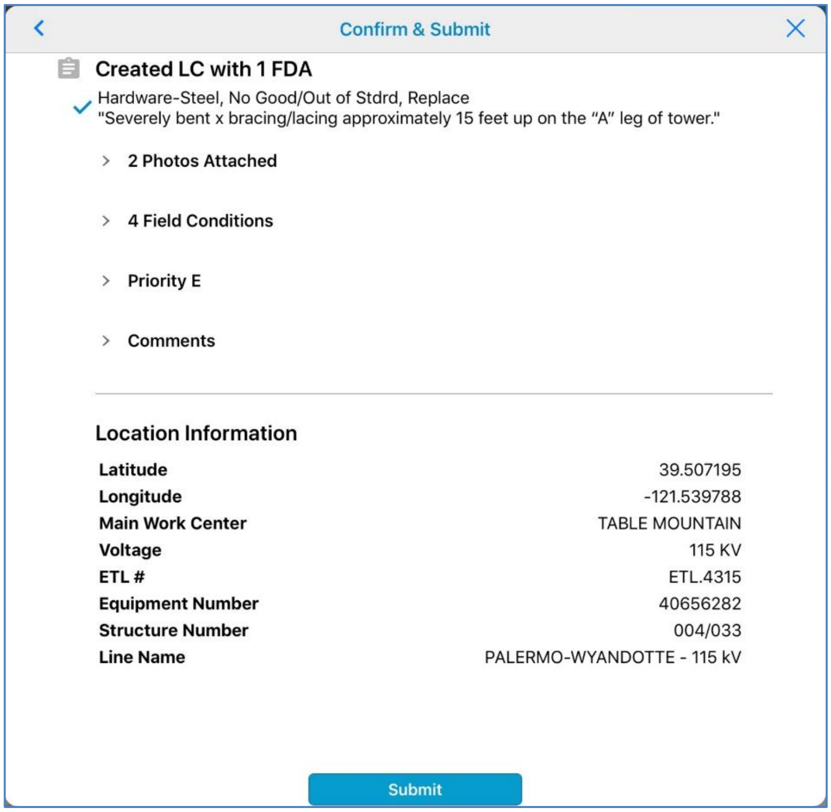

Figure 10: Review Data, Confirm and Submit