November 26, 2025
Docket # 2026-2028-Base-WMPs

PacifiCorp 2026-2028 Wildfire Mitigation Plan_R1 – Appendix F Attachment List

Standard or Policy	Section Referenced
Transmission and Distribution System Condition Priorities and Correction Timelines Asset Management Policy No 292	Section 8.5.2
Detailed Inspections for T&D Lines Asset Management Policy 009	Section 8.5
Clearance Table for Distribution and Transmission Line Inspectors NESC and GO 95 Grandfathering Matrix Facility Point Inspection NESC and GO 95 Frequently Asked Questions Condition Code Dropdowns Asset Management Procedure 069	Section 8.3
Visual Assurance Inspections —Safety Patrol of G Transmission and Distribution Lines Asset Management Policy No 011	Section 8.3
Helicopter Standard Operating Procedure for Line Inspections Facility Inspection Procedure No 203	Section 8.3
Wood Pole Test & Treatment Transmission and Distribution Lines Asset Management Policy 013	Section 8.3.3
Substation inspection Asset Management Policy No 034	Section 8.3.4
Policy 001 Maintenance Intervals for Apparatus, Relays, Meters, Line Patrol/Inspections, Wires Equipment and Communications Equipment	Section 8.4
Exhibit M.07 Performance Based Requirements for Pacific Power Detailed Inspections and Detailed Test and Treat Activity	Section 8.5
Operating Transmission and Distribution Assets During periods of Elevated Wildfire Risk Power Delivery Policy PAC-1000	Section 8.7
Operating Bulk Electric System (BES) Transmission Assets During Identified Wildfire Risk System Operations Procedure SOP-200	Section 8.7
Operating Sub-Transmission Assets During Identified Wildfire Risk System Operations Procedure SOP-201	Section 8.7
Operating Distribution Assets During Identified Wildfire Risk System Operations Procedure, SOP-202	Section 8.7
Example of a Daily Work Evaluation Summary Record	Section 8.7.3
PacifiCorp's Transmission & Distribution Vegetation Management Program Standard Operating Procedures (SOP), Revision 8, dated 8/29/2024	Section 9
Transmission Grid Operations Operating Procedure PCC-215 Guidelines for Communication of Vegetation Conditions that Present an Imminent Threat of Transmission Line Outage	Section 9.2
Wildfire Encroachment System Operations Procedure SOP-203	Section 11
PSPS Execution Playbook	Section 11
Annex 01: 2025 Public Safety Power Shutoff Community Resource Center Playbook	Section 11
Emergency Response Plan (ERP), Sixth edition, dated April 23, 2025	Section 11
R1812005 PacifiCorp Annual AFN Plan 2025 1-31-25	Section 11

TRANSMISSION AND DISTRIBUTION SYSTEM CONDITION PRIORITIES AND CORRECTION TIMEFRAMES

Asset Management Policy No. 292

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Approved Location: Pdxshrn104\shr04\Eng\Publications\DIS\POL
File Number-Name: 292-Transmission and Distribution System Condition Priorities.docx
Revision Number: 4
Revision Date: 1/22/2025

Summary of Policy: Provide correction time periods for Transmission and Distribution lines.

Affected Departments: Transmission & Distribution Operations (Line)
Field Inspection Support

Document Security Category			
	Confidential	X	Internal
	Restricted		External
			BES Cyber System Information (BCSI)

Revision Log		
0	4/12/2014	Original policy created.
1	10/3/2022	Updated correction timeframes for fire threat conditions.
2	12/19/2022	Update policy to reflect Energy Release Risk language specified in Procedure 069.
3	5/23/2024	Updated to include new "I" priority for imminent threat conditions. In addition, charts, text, and other policy references were updated to match current practices.
4	1/22/2025	Revised to include applicability across all states served by PacifiCorp. Retired Policies 192 and 295, which were specific to California and Oregon.

TRANSMISSION AND DISTRIBUTION SYSTEM CONDITION PRIORITIES AND CORRECTION TIMEFRAMES

Asset Management Policy No. 292

1 Scope

This policy and the accompanying work practices apply to PacifiCorp's employees and contractors managing conditions identified during inspections of transmission and distribution facilities in California, Idaho, Oregon, Utah, Washington, and Wyoming. It also applies to PacifiCorp-owned transmission facilities in Montana, Colorado, and New Mexico.

The policy covers condition corrections for which PacifiCorp is responsible. Establishing correction timeframes for conditions attributable to other parties—such as communication infrastructure providers or customers—is outside the scope of this policy unless explicitly stated.

These measures are designed to ensure compliance with the National Electrical Safety Code (NESC), state-specific regulatory requirements (including California's General Order 95), PacifiCorp policies, and construction standards. PacifiCorp's Facility Point Inspection (FPI) system will be used to document inspections, record conditions with assigned priority levels, and track correction dates.

This policy does not apply to PacifiCorp's substation, communication, general plant, or generation facilities.

2 References

National Electrical Safety Code (NESC)

State of Oregon Public Utility Commission Chapter 860, *Division 24 Safety Standard Rules*

State of California General Order 95, *Rules for Overheard Electric Line Construction*

State of California General Order 128, *Rules for Construction of Underground Electric Systems*

California Decision 17-12-024 *Decision Adopting Regulations to Enhance Fire Safety in the High Fire-Threat District, December 14, 2017*

California Decision 18-05-042 *Decision Approving A Settlement Agreement That Amends Rule 18 of General Order 95, May 31, 2018*

PacifiCorp Policy 011, *Visual Assurance Inspections for T&D Lines*

PacifiCorp Policy 009, *Detailed Inspections for T&D Lines*

PacifiCorp Policy 013, *Wood Pole Test & Treatment for T&D Lines*

PacifiCorp Procedure 069, *Clearance Table for Distribution and Transmission Line Inspectors, NESC and GO 95 Grandfathering Matrix, and Condition Code Dropdowns*

3 Definitions

- **Condition –** The state of something with regard to appearance, quality, or working order which can sometimes be used to identify potential impact to normal system operation or clearance, which is typically identified by an inspection.
- **Condition Code –** Predetermined list of codes for use by inspectors to efficiently capture, categorize, and communicate observations and inform the scope of and timeline for potential corrective action.
- **Correction –** Scope of work required to remove a Condition within a specified time period.
- **Energy Release Risk Condition –** A type of condition that, under certain circumstances, can correlate to increase risk of a fault event and potential release of energy at the location of the condition.
- **FPI (Facility Point Inspection) –** PacifiCorp's source of records for captured conditions.
- **GISMO (Geographic Information Systems Maintenance Organizer) –** PacifiCorp's application which pulls data from FPI and is used as an operational tool to view, filter, and export open conditions.
- **Imminent Threat –** Condition that poses an immediate safety/or reliability risk.
- **Priority Level –** The level of risk assigned to the Condition observed.
- **Suggested Correction Date –** A date in GISMO set based on condition priority.

4 Condition Priority Levels

PacifiCorp's FPI system has a predetermined list of condition codes for use by inspectors to efficiently capture, categorize, and communicate observations to inform the scope of potential corrective actions. The system documents the date of inspection and establishes the timeline for correction based on priority. Each Condition Code is assigned Priority Levels, as follows:

4.1 Priority I

Conditions where there's an imminent threat to safety or reliability with high probability of significant impact. These conditions pose a significant present threat to human life or property and corrective action shall be taken immediately, either by fully repairing or by temporarily repairing and reclassifying the condition to a lower priority. "I" priorities do not conform with NESC and align with California's GO 95 Level 1 priority levels (GO 95 18-B-1-a) and Oregon Administrative Rules 860-024-0012 (1).

4.2 Priority A

Conditions that do not conform to the NESC and meet the requirements for an "A" priority as called for in PacifiCorp's Policies 009, 011, 013 and Procedure 069, or that in the opinion of the inspector demonstrate a moderate to high risk of potential impact to safety or reliability but are not imminent and do not require immediate repair. "A" Priorities align with California's GO 95 Level 2 priority levels (GO 95 18-B-1-a) and Oregon Administrative Rules 860-024-0012 (2).

4.3 Priority B

Conditions that do not conform to the NESC and meet the requirements for a "B" priority as called for in PacifiCorp's Policy 013 and Procedure 069, or that in the opinion of the inspector demonstrate a low to moderate risk level to safety or reliability. "B" Priorities align with GO 95 Level 2 priority levels (GO 95 18-B-1-a) and Oregon Administrative Rules 860-024-0012 (2).

4.4 Priority C

Conditions where there's an acceptable to low risk of impact to safety or reliability. "C" priorities align with GO 95 Level 3 priority levels (GO 95 18-B-1-a). "C" priorities are only assigned to locations in California.

4.4 Priority D

Conditions where there's no corrective action required but it's desirable to record informational issues for engineering and planning purposes are given priority "D". Common examples include documenting locked gates or specific equipment that is no longer in use.

4.5 Priority G

Conditions where there's an exemption from corrective action due to the age of the equipment. Grandfathered priorities are considered conforming, they are recorded for future inspection references and audit purposes.

5 Condition Priority Assignments

During inspections, inspectors document potential violations or noteworthy observations by assigning a Condition Code and Priority Level in PacifiCorp's Facility Point Inspection (FPI) system, following PacifiCorp Procedure 069. Once conditions are entered into FPI, the GISMO application tool generates Suggested Correction Dates. Corrections are then planned with the goal of completion on or before the GISMO Suggested Correction Date. These Suggested Correction Dates often exceed compliance requirements, meaning corrections completed after the GISMO date but before the compliance deadline are still compliant. Setting GISMO correction dates ahead of regulatory deadlines encourages early completion of required work.

5.1 Correction Time Periods for California

Correction time periods are assigned to align with GO 95 Rule 18. PacifiCorp Procedure 069 also categorically designates applicable Condition Codes as Fire Risk Conditions, a subset of conditions requiring accelerated correction timeframes per GO 95 Rule 18, as amended by D.17-12-024 and effective under D.18-05-042.

PacifiCorp differentiates Level 2 conditions by assigning them "A" and "B" priorities. While both align with GO 95 requirements, "A" priorities are addressed sooner than "B" priorities. It is important to note that Suggested Correction Dates may be adjusted over time to reflect changes in regulations or operational efficiency requirements. Upon completing corrections, the FPI system must be updated to include details of the work performed, the completion date, and the identities of the personnel involved.

GO 95 Priority	Company Priority	Energy Release Risk[1]	CA Suggested Correction Period			GO 95 Compliance Requirements[2]		
			Non-Tier	Tier 2	Tier 3	Non-Tier	Tier 2	Tier 3
Level 1	I[2]	All	Immediately	Immediately	Immediately	Immediately	Immediately	Immediately
Level 2	A	Y	30 days	30 days	30 days	12 months	12 months	6 months
	A	N	30 days	30 days	30 days	12 months	12 months	12 months
Level 2	B	Y	36 months	6 months	6 months	36 months	12 months	6 months
	B	N	36 months	36 months	36 months	36 months	36 months	36 months
Level 3	C	N	36 months	36 months	36 months	60 months	60 months	60 months

5.2 Correction Time Periods for Idaho, Oregon, Utah, Washington, and Wyoming

Correction time periods are assigned to address NESC noncompliance issues and aligns with state requirements where applicable.

Company Priority	Energy Release Risk[3]	Suggested Correction Period					
		Idaho, Utah, Wyoming		Washington		Oregon	
		Non-FHCA	FHCA	Non-FHCA	FHCA	Non-FHCA	FHCA
I[4]	All	Immediately	Immediately	Immediately	Immediately	Immediatel y	Immediately
A	Y	120 days	60 days	120 days	30 days	30 days	30 days
A	N	120 days	120 days	120 days	120 days	30 days	30 days
B	Y	24 months	12 months	24 months	6 months	24 months	6 months
B	N	24 months	24 months	24 months	24 months	24 months	24 months

[1] Energy Release Risks are determined and distinguished in Procedure 069. These conditions may pose a fire risk.

[2] Compliance period in accordance with GO 95. "A" priority may compromise worker safety and correction period is shown as 12 months instead of 36 months. Before June 30, 2019, when the correction time periods were modified to account for the High Fire Threat District, correction time period was immediately for Level 1 and 59 months for Level 2. No time period was established for Level 3 priorities.

[2] Imminent Threat conditions were created May 2024 to differentiate conditions that require immediate repair.

[3] Energy Release Risks are determined and distinguished in Procedure 069. These conditions may pose a fire risk.

[4] Imminent Threat conditions were created May 2024 to differentiate conditions that require immediate repair.

5.3 Conditions with Corrective Time Period Exceptions

PacifiCorp has evaluated these specific Condition Codes and assigned a Suggested Correction Date consistent with the level of risk. The table below shows the Condition Codes with alternative corrective time periods from what is shown above.

Description	Condition Code	Priority	Energy Release Risk	Locations	Rationale
Climbing Hazard	CLMBHAZ GO95CLMP	B/C	N	12 Months (CA)	Potential violation can impact worker safety; an expedited period is assigned.
Pole Decay (Replace/Restore)	POLEDERP POLEREST	A	Y	90 Days	The risk level associated with this level A is indicative of a 120-day level risk unless it is an imminent threat.
Pole Damage (Replace/Restore)	POLEREPL POLEDMRS	A	Y	90 Days	
Unable Inspect	CANTINSP INSPISSU VEGCANTI	ALL	ALL	Due on 12/31 of same year as inspection date	Reasonable correction is to complete inspection during calendar year inspection was scheduled.
Bird Damage	BIRDDMG	B	N	2 years (CA) 1 year (OR)	Nesting and environmental regulations may require additional time to correct.

5.4 Exceptions to All Corrective Action Time Periods

Correction time periods may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies, such as fires or severe weather conditions, etc.

These exceptions to the correction time periods are to be documented in GISMO.

END

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Policy

DETAILED INSPECTIONS FOR T & D LINES

Asset Management Policy No. 009

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Approved Location:	Pdxshrn104\shr04\Eng\Publications\FPP\DIS\POL
File Number-Name:	009-Detail Inspection T&D Lines.docx
Revision Number:	R14
Revision Date:	1/22/2025

Document Security Category			
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X	Internal		

Revision Log		
7	9/26/08	Clarify inspection requirements.
8	8/16/12	Update per PacifiCorp initiatives.
9	10/26/12	Clarify A and B definitions.
10	6/2/14	Reference new/revised policies re: priorities/correction timeframes, separate CA.
11	1/20/17	Added policy references and added inspection acknowledgement to section 1.
12	5/23/23	Reviewed to ensure compliance with NESC 2023.
13	9/4/24	Updated reference list.
14	1/22/25	Applied policy to all PacifiCorp states. Policy 297 discontinued.

Policy

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DETAILED INSPECTIONS FOR T & D LINES

Asset Management Policy No. 009

1 Scope

The policies, procedures, and work practices that follow apply to all PacifiCorp employees and contract employees who perform inspections on PacifiCorp's transmission and distribution systems across all PacifiCorp states. All federal, state, local, and PacifiCorp requirements are to be strictly adhered to at all times.

The inspection cycle for detailed inspections shall be recommended by Asset Management. The cycles are based on statutory requirements of the various states served by PacifiCorp as well as age, climate, location, performance history, and operational considerations associated with these assets.

Detailed inspections are intended to be careful visual inspections accomplished by visiting each structure as well as inspecting spans between structures. These precautionary inspections are intended to and shall be adequate to identify nonconformance with the National Electrical Safety Code (NESC), California General Orders 95 and 165 (GO-95 and GO-165), and Oregon Administrative Rules 860-024, PacifiCorp construction standards, infringement by other utilities or individuals, defects, potential hazards, and deterioration of the facilities which need to be corrected to maintain safe and reliable service.

By entering a completed inspection, which is uploaded into the Facility Point Inspection (FPI) system, the inspector is confirming that they have performed the inspection per the applicable requirements of this policy, including recording conditions found during the performance of the inspection. Items that are found to be nonconforming shall be considered out of compliance and shall be noted and entered into PacifiCorp's FPI system. The appropriate coding for the condition discovered shall be entered along with any appropriate comments.

The FPI system allows codes to be assigned to the conditions, which are used for prioritizing subsequent repair work. Each condition shall have the appropriate priority code assigned as per the policies in the following References section.

After an existing condition has been corrected, the FPI database must be updated to reflect the changes.

2 References

NESC Rules

State of Oregon Administrative Rules 860-024

PacifiCorp Procedure 069, *Clearance Table, Grandfathering Matrix, Dropdown Codes*

PacifiCorp Policy 011, *Visual Assurance*

PacifiCorp Policy 013, *Wood Pole Test and Treat*

PacifiCorp Policy 292, *Transmission & Distribution System Condition Priorities and Correction Timeframes*

PacifiCorp Policy 305, *State of Oregon - Service Conductor Clearances Over Driveways*

PacifiCorp Policy 336, *State of Oregon -Nonconformance Issues Involving Clearance of Overhead Services over Pedestrian Areas*

PacifiCorp Policy 307, *State of Idaho, Utah, and Wyoming Nonconformance Issues Involving Clearance of Overhead Services*

3 Overhead Facilities

A wide array of conditions may be encountered during a detailed inspection. Some items that may typically be discovered are outlined in this section. For more detailed information on NESC and GO-95 required clearances and grandfathering, see PacifiCorp Procedure 069.

Facilities temporarily out of service shall be inspected in the same general manner as in-service facilities so as to not create a hazard per NESC Rule 214.B.2 and GO-95 Rule 31.2. Facilities permanently abandoned shall be removed or inspected and maintained in a safe condition per NESC Rule 214.B.3 and GO-95 Rule 31.6.

3.1 Poles

a) Perform a visual examination of the entire area above the ground portion of wood poles and record significant abnormalities including but not limited to damage caused by lightning, fire, birds or insects, excessive checks, cracks, splits, surface rot or shell rot, mechanical damage, badly leaning poles, badly deteriorated tops, and poles where the adjacent ground is sliding or being eroded.

b) For woodpeckers: Woodpecker holes should be reported as bird damage, code BIRDDMG. All poles with woodpecker damage shall be evaluated in accordance with PacifiCorp Policy 045 *Woodpecker Damage Repair and Replacement for Wood Poles;* and Policy 013 *Wood Pole Test and Treat.*

c) For pole test and treat inspections: If a detailed inspection is being performed in conjunction with PacifiCorp's pole test and treat inspection, then the requirements of PacifiCorp Policy 013, *Wood Pole Test and Treat* shall be adhered to.

d) Poles must meet all clearance requirements from railroads.

e) Poles must meet all clearance requirements from curbs.

f) Poles must have an 8-foot vertical clear zone so that they are not readily climbable. Pole steps must be removed up to 8 feet above any accessible surface, and the holes must be treated and then plugged.

g) Poles must have required clearances from fire hydrants. See PacifiCorp Procedure 069 and current NESC/GO-95 editions.

h) All poles and anchors must be properly backfilled.

i) In California, the top of high-voltage signs on poles shall be located a maximum of 40 inches below the lowest line conductor of more than 750 volts, or wood cross-

arms may be marked by placing one high-voltage sign on the pole/cross-arm per GO-95 Rule 51.6A.

3.2 Underground Dip Pole Equipment

a) All conduit joints must be intact.

b) All metal conduits are to be properly grounded.

c) PVC conduits are not crushed or broken.

d) Conduits are not readily climbable.

e) Stress cones and pot heads have no visible tracking or leaking oil.

f) All conduit attachments are in place and tight.

3.3 Guys

a) See PacifiCorp Procedure 069 and the current NESC/GO-95 edition to identify when a guy insulator or effective grounding to the neutral/pole is necessary.

b) Strain insulators may not be cracked or broken.

c) Guy insulators must be installed such that they would remain below the neutral and at least 8 feet above the ground if the guy were to break (not required if the guy is bonded). In California, the guy anchor rod is considered to be securely grounded per GO-95 Rule 21.4-C

d) Proper tension on the guy wire must be provided to support the pole. However, a slack guy is acceptable if the pole is in the proper vertical position. In California, All guys must be maintained taut per GO-95 Rule 56.2.

e) Guy markers must be installed in pedestrian areas and parking areas. In California, Guy markers must be installed on the outermost guy on every anchor (GO-95 Rule 56.9).

f) All guy wire tails must be properly cut at time of inspection.

3.4 Anchors

a) Tree anchors are not acceptable and must be removed and replaced with a standard anchor.

b) Anchor rods may extend above the ground line if they can support the pole and have proper guy markers.

c) Note any signs of anchor rod corrosion.

3.5 Grounding

a) Ground rods must be flush with the ground or below ground level. In California, The ground rod must be buried a minimum of one foot (PacifiCorp Standard DG 051, GO-95 Rule 59.4A).

b) The ground wire must be intact and properly connected. In California, the ground wire must be at least #8 AWG copper or equivalent and those attached to common neutral systems must be a minimum #4 AWG.

c) Molding

1) If a multi-grounded neutral is present, no ground molding is required.

2) If no neutral exists, the bottom 8 feet of the ground wire is required to have molding.

In California, all grounding conductors attached to the face or underside of the wood cross-arm and the surface of wood poles shall be covered with an approved molding.

d) Transmission hardware bonding.

1) For 69 kV – 138 kV, hardware with less than 8 inches separation shall be bonded to the ground.

2) For 161 kV – 230 kV, hardware with less than 12 inches separation shall be bonded to the ground.

3.6 Climbing Space

a) Adequate space should exist for climbing through PacifiCorp facilities, communications facilities, and for telephone and cable TV personnel.

b) Climbing space requirements apply to all portions of structures from ground level up through pole top.

c) Bolts must not protrude more than 4 inches out from the nut when below a transformer, or in the communication climbing space.

d) Insulated covers are required on bolts extending into the climbing space when attached to deadend hardware

3.7 Service Conductors

a) See PacifiCorp Procedure 069 and current codes for minimum clearances required to be maintained between service conductors and the following:

- Other circuits and supporting structures
- Communications facilities at the pole and at the weatherhead
- Communications facilities carried on the same pole and carried on different poles
- Roofs, decks, and balconies
- Windows
- Buildings, signs, trees, antennas, etc.
- Over roads, driveways, walkways, railroads, swimming pools, hot tubs, etc.
- Streetlight masts
- Supporting structures such as poles and the sides of buildings

Policy

b) See PacifiCorp Policies, PacifiCorp Procedure 069, and PacifiCorp Policy 336, *State of Oregon Nonconformance Issues Involving Clearance of Overhead Services over Pedestrian Areas* for current required clearance for drip loops above ground.

c) Bare connectors and bare conductors near weatherheads and less than 12.5 feet above the ground are a Priority A condition.

d) Check for signs of heating in the insulation and verify that the insulation is intact.

e) All deadends must be intact and secure on both ends.

f) The service coil must not be tied to the pole.

g) A service attached to a tree is not nonconforming as long as the tree is healthy and structurally sound.

h) See additional requirements for California

- Proper clearance from communications facilities must be provided. Vertical clearance is 48 inches at the pole, but may be reduced to 36 inches if the cable is neutral supported (triplex or parallel lay). If there is an open wire and no guard arm, 72 inches is required.

- There must be 12 inches clearance above the metal parts of a street light and 24 inches to the metal parts of the mast.

- Services shall not be less than 10 feet above areas accessible to pedestrians only. Exceptions are allowed with 8.5 feet for services that cannot in any practical way provide 10 feet of clearance.

3.8 Secondary Service Conductors

a) See PacifiCorp Procedure 069 and current NESC codes for clearances required to be maintained between secondary service conductors and:

- Buildings, signs, antennas, etc.
- Communications facilities where they cross paths, i.e., when carried on different poles
- Communications facilities at the pole and mid-span

b) All open secondary wires must be properly sagged.

c) Secondaries must have parallel lay and must be sagged properly with no loose lashing wire and must be properly guyed.

d) In California, vertical clearance to the communication cable is 48 inches at the pole and 43 inches mid-span. Clearance mid-span can be reduced to 36 inches if cabled secondary conductors are insulated with abrasion resistant material and supported by the neutral.

3.9 Transformers, Circuit Breakers, Capacitors, Regulators, Etc.

a) Equipment cases and frames must be properly grounded.

b) Oil leaks shall be noted.

c) All bushings must be intact.

d) Mounting hardware must appear tight and secure.

e) Idle facilities shall be inspected and must meet NESC requirements.

f) Cutout jumpers must be clear of hardware and the mounting must appear tight.

g) Arresters must be intact and properly grounded.

3.10 Switches and Disconnects

a) Switches and disconnects must be intact and secure.

b) Operating handles must be locked and in good physical condition.

c) Switches that are broken, need adjustment or are mounted improperly, etc., shall be identified as nonconforming.

d) The operator's platform area must be clean and properly insulated or grounded.

e) Transmission switches (46 kV and above) require that the handle be bonded to the switch platform with 1/0 copper wire.

3.11 Crossarms and Braces

a) Crossarms may not be excessively split, broken, burned, or deteriorated.

b) Crossarm braces must be secure and may not be bent, broken, or excessively rusted or corroded.

c) Cross-braces must be sound and secure.

3.12 Insulators

Refer to PacifiCorp Policy 012 *Damaged Insulator Replacement* for detailed guidelines.

a) Insulator glass must be intact and not cracked, broken, badly chipped, or gunshot.

b) Insulator must not be contaminated, i.e., excessive pollution or bird droppings.

c) The polymer coating around the rod may not be cut (this may be difficult to see). If a cut is observed, the insulator must be recorded as Priority A condition for replacement.

d) Pins and posts must be securely attached to the pole or crossarm.

e) Tie wires, deadend clamps, suspension shoes, and post clamps must be secure.

f) For transmission polymer insulators on lines 230 kV and over, there must be a corona ring on the hot end of the insulator and it must be installed in the proper direction.

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3.13 Transmission and Distribution Primary Conductors

a) See PacifiCorp Procedure 069 and current codes for minimum clearances required to be maintained between transmission/distribution primary conductors and the following:

- Conductors of the same circuit and supporting structures
- Other circuits and other supporting structures
- Communications facilities
- Land/ground, including pedestrian areas, traffic areas, agricultural/pastureland, railroads, etc.
- Waterways, swimming pools, etc.
- Structures such as signs, antennas, bridges, buildings, etc.

b) Conductors must be properly sagged.

c) Conductor strands must not be broken, frayed, or basketed.

d) Proper clearances must be maintained.

3.14 Street Lights

a) See PacifiCorp Procedure 069 and current NESC/GO-95 codes for required clearances for:

- Drip loop and communications, whether the insulated wire is covered or not
- Mast and communications, whether grounded or not,

b) If the streetlight is owned by PacifiCorp, the lens must not be broken and the lamps must be in place.

c) All parts of street lighting equipment may be no less than 12 inches above or 24 inches below the level of messengers or conductors supported by messengers.

3.15 Fenced Industrial Enclosures

a) Gates must be secure, serviceable, locked, and properly grounded.

b) Fences must be secure from top to bottom and must be properly grounded.

c) Enclosures must be clean and free of vegetation and foreign material.

d) High-voltage signs must be present and must be properly installed.

e) Minimum clearances must be provided.

END

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Procedure

Clearance Table for Distribution and Transmission Line Inspectors
NESC and GO 95 Grandfathering Matrix
Facility Point Inspection NESC and GO 95 Frequently Asked Questions
Condition Code Dropdowns

Asset Management Procedure 069

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Approval:	Alex Vaz
Authoring Department:	Asset Management
Approved Location:	DFS\PDXCO\SHR04\Publications\FPP\DIS\PRO
File Number-Name:	069-Clearance Table, Grandfathering Matrix, FAQ and Dropdown Codes.xls
Revision Number:	R28
Revision Date:	12/20/2024

The most current version of this document is posted to engineering's intranet page for distribution forms, policies and procedures.
Master file located on the Engineering drive \\J:\Publications\FPP\DIS\PRO
Modification of this document must be approved by the authoring department and processed by engineering publications,

PacifiCorp's Inspection Clearance Table ** (Do not use Table for construction, See Construction Standards)

All distances are minimums required by the NESC at worst conditions, 3300' elev. or below. For more details see Transmission standards, section TC.

Modified Last: 7/10/2023 0:00

Upper Level

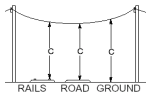

Fig. 1

	Insulated com. conductors; messengers; surge protection wires; guys; neutral conductors meeting Rule 230E1; supply cable meeting Rule 230C1	Supply cables of 0-750V meeting Rules 230C2 or C3	Non insulated com. conductors; Unguarded rigid live parts 0-750V	Supply cable over 750V meeting Rules 230C2 or 230C3; open supply conductors, 0-750 V;	Open Supply Conductors: Over 750V to 8.7kV to ground	Over 8.7V to 22kV to grnd (34.5 kV to phase)	Over 22 kV to 27 kV to gnd (46 kV to phase)	Over 28 kV to 42 kV to grd (69 kV to phase)	Over 42 kV to 70 kV to grd (115 kV to phase)	Over 70 kV to 84 kV to gnd. (138 kV to phase)	Over 84 kV to 98 kV to grd (161 kV to phase)	Over 98 kV to 140 kV to gnd. (230 kV to phase)	Over 140kV to 210kV to grd (345kV to phase)	Nonmetallic, effective grounded support arms and equipment cases	Ungrounded cases that contains equip. on 750V or less	Ungrated Ridge live parts and Cases on 750-22kV
Ground Clearance - Where wires, conductors, or cables crossover or overhang														Where rigid part over hang or are along NESC 232B3		
1 Track rails of railroad (except electrified railroads using overhead trolley conductors	23.5'	24.0'	24.0'	24.5'	26.5'	26.5'	26.7'	27.5'	28.5'	28.9'	29.3'	30.7'	33.0'	--	--	--
2 Roads, streets, and other areas subjected to truck traffic.	15.5'	16.0'	16.0'	16.5'	18.5'	18.5'	18.7'	19.2'	20.2'	20.6'	21.0'	22.4'	24.7'	15.0'	16.0'	18.0'
3 Driveways, established parking areas, and alleys	15.5'	16.0'	16.0'	16.5'	18.5'	18.5'	18.7'	19.2'	20.2'	20.6'	21.0'	22.4'	24.7'	15.0'	16.0'	18.0'
4 Other land traversed by vehicles, such as cultivated, grazing, forest, orchard, etc.	15.5'	16.0'	16.0'	16.5'	18.5'	18.5'	18.7'	19.2'	20.2'	20.6'	21.0'	22.4'	24.7'	15.0'	16.0'	18.0'
5 Spaces and ways subject to pedestrians or restricted traffic only.	9.5'	12.0'	12.0'	12.5'	14.5'	14.5'	14.7'	15.2'	16.1'	16.6'	17.0'	18.4'	20.7'	11.0'	12.0'	14.0'
Vertical Clearance - Conductors & cables on different supports				Upper level												
1 Insulated com. conductors; messengers; surge protection wires; grounded guys; ungrounded guys exposed to 0-300 V; neutral conductors meeting Rule 230E1; supply cable needing Rule 230C1	2.0'	2.0'	2.0'	2.0'	4.0'	4.0'	4.2'	4.7'	5.6'	6.1'	6.5'	7.9'	10.2'			
2 Non insulated communication conductors; supply cables of 0-750 V meeting Rules 230C2 or 230 C3	2.0'	2.0'	2.0'	2.0'	6.0'	6.0'	6.2'	6.7'	7.6'	8.1'	8.5'	9.9'	12.2'			
3 Supply cable over 750V meeting Rules 230C2 or 230C3; open supply conductors, 0-750 V; ungrounded guys exposed to 300-750 V	4.0'	2.0'	2.0'	2.0'	2.0'	2.0'	2.2'	2.7'	3.6'	4.1'	4.5'	5.9'	8.2'			
4 Over 750V to 22kV to ground (34.5 kV to phase)	--	--	--	--	2.0'	2.0'	2.2'	2.7'	3.6'	4.1'	4.5'	5.9'	8.2'			
5 Over 22 kV to 27 kV to ground (46 kV to phase)	--	--	--	--	--	--	2.3'	2.8'	3.8'	4.2'	4.7'	6.1'	8.4'			
6 Over 28 kV to 42 kV to ground (69 kV to phase)	--	--	--	--	--	--	--	3.3'	4.3'	4.7'	5.2'	6.6'	8.9'			
7 Over 42 kV to 70 kV to ground (115 kV to phase)	--	--	--	--	--	--	--	--	5.2'	5.7'	6.1'	7.5'	9.8'			
8 Over 70 kV to 84 kV to ground 138 kV to phase)	--	--	--	--	--	--	--	--	--	6.1'	6.6'	8.0'	10.3'			
9 Over 84 kV to 98 kV to ground (161 kV to phase)	--	--	--	--	--	--	--	--	--	--	7.1'	8.5'	10.8'			
10 Over 98 kV to 140 kV to ground (230 kV to phase)	--	--	--	--	--	--	--	--	--	--	--	9.9'	12.2'			
Vertical Clearance - Between conductors on the same supports																
1 **Communication Conductors & Cables**																
a Located in Communication Space	40.0"	40.0"	40.0"	40.0"	40.0"	40.0"	40.0"	40.0"	47.0"	52.0"	56.9"	73.7"	101.3"			
b Located in Supply Space	16.0"	16.0"	16.0"	16.0"	16.0"	40.0"	40.0"	40.0"	47.0"	52.0"	56.9"	73.7"	101.3"			
2 **Open Supply Conductors & Cables**																
a Open conductors 0 to 8.7 kV; Supply Cable meeting Rule230C1,2,or3; Neutral cond. Rule 230E1.	16.0"	16.0"	16.0"	16.0"	16.0"	21.6"	23.6"	29.6"	40.8"	46.4"	52.0"	68.8"	96.4"			
b Over 8.7 kV to 22 kV to ground	--	--	--	--	--	30.1"	32.1"	38.1"	49.3"	54.9"	60.5"	77.3"	104.9"			
c Over 22 kV to 27 kV to ground (46 kV to Phase)	--	--	--	--	--	32.1"	34.1"	40.1"	51.3"	56.9"	62.5"	79.3"	106.9"			
d Over 27 kV to 42 kV to ground (69 kV to Phase)	--	--	--	--	--	--	--	46.1"	57.3"	62.9"	68.5"	85.3"	112.9"			
e Over 42 kV to 70 kV to ground (115 kV to Phase)	--	--	--	--	--	--	--	--	68.5"	74.1"	79.7"	96.5"	124.1"			
f Over 70 kV to 84 kV to ground (138 kV to Phase)	--	--	--	--	--	--	--	--		79.7"	85.3"	102.1"	129.7"			
g Over 84 kV to 98 kV to ground (161 kV to Phase)	--	--	--	--	--	--	--	--			90.9"	107.7"	135.3"			
h Over 98 kV to 140 kV to ground (230 kV to Phase)	--	--	--	--	--	--	--	--				124.5"	152.1"			
i Over 140kV to 210kV to ground (345kV to Phase)													179.7			
Clearances of Wires, Conductors and Cables, & Unguarded Rigid Live Parts - Adjacent but Not Attached to Buildings & Other Installations Except Bridges. No Wind																
1 **Buildings**																
Horizontal to Walls, projections and guarded windows,	4.5'	5.0'	5.0'	5.5'	7.5'	7.5'	7.7'	8.2'	9.1'	9.6'	10.0'	11.4'	13.7			
Vertical over or under roofs or projections not readily accessible to persons	3'	3.5'	10.0'	10.5'	12.5'	12.5'	12.7'	13.2'	14.1'	14.6'	15.0'	16.4'	18.7			
Vertical to decks, balconies, roofs, etc., accessible to persons, and over roofs not accessible to trucks	9.5'	10.0'	10.0'	10.5'	14.5'	14.5'	13.7'	14.2'	15.1'	15.6'	16.0'	17.4'	19.7			
Vertical over roofs, ramps, and loading docks accessible to trucks	15.5'	16.0'	16.0'	16.5'	18.5'	18.5'	18.7'	19.2'	20.1'	20.6'	21.0'	22.4'	24.7			
2 **Signs, chimneys, billboards, antennas, tanks, and other installations not classified as buildings or bridges**																
Horizontal	3.0'	3.5'	5.0'	5.5'	7.5'	7.5'	7.7'	8.2'	9.1'	9.6'	10.0'	11.4'	13.7			
Vertical over or under	3.0'	3.5'	5.5'	6.0'	8.0'	8.0'	8.2'	8.7'	9.6'	10.1'	10.5'	11.9'	14.2			
3 **Other supporting structures, wires, conductors, or cables of one line passing near lighting support, traffic signal support, or a supporting structure of a second line, not attached**																
Horizontal	5.0'	5.0'	5.0'	5.0'	5.0'	5.0'	5.0'	5.0'	5.7'	6.1'	6.6'	8.0'	10.3			
Vertical	4.5'	4.5'	4.5'	4.5'	5.5'	5.5'	5.5'	5.5'	6.2'	6.6'	7.1'	8.5'	10.8			
4 Vertical clearance to service (0 - 750 V), not readily accessible to pedestrians, that meets or terminates at a through-the-roof support & does not cross more than 6' of roof or is 4' or less from the roof edge shall be 18 inches. * See Standard TC-151 page 10.																
Clearances of Wires, Conductors and Cables From Bridges																
1 **Clearance over bridges.**																
a. Attached	3.0'	3.0'	3.0'	3.5'	5.5'	5.5'	5.7'	6.2'	7.1'	7.6'	8.0'	9.4'	11.7			
b. Not attached	10.0'	10.0'	10.0'	10.5'	12.5'	12.5'	12.7'	13.2'	14.1'	14.6'	15.0'	16.4'	18.7			
2 **Clearance beside, under or within bridge structure**																
a. Readily Accessible portion of bridge																
Attached	3.0'	3.0'	3.0'	3.5'	5.5'	5.5'	5.7'	6.2'	7.1'	7.6'	8.0'	9.4'	11.7			
Not attached	5.0'	5.0'	5.0'	5.5'	7.5'	7.5'	7.7'	8.2'	9.1'	9.6'	10.0'	11.4'	13.7			
b. Ordinarily inaccessible portions of bridge																
Attached	3.0'	3.0'	3.0'	3.5'	5.5'	5.5'	5.7'	6.2'	7.1'	7.6'	8.0'	9.4'	11.7			
Not attached	4.0'	4.0'	4.0'	4.5'	6.5'	6.5'	6.7'	7.2'	8.1'	7.6'	9.0'	10.4'	12.7			
Clearances of Wires Conductors and Cables Over Or Near Swimming Pools																
1 Clearance in any direction from the water, edge of pool, or base of diving platform. (Figure 8, "A")	22.5'	23.0'	22.5'	23.0'	25.0'	25.0'	25.2'	25.7'	26.6'	27.1'	27.5'	28.9'	31.2			
2 Clearance to diving platform, tower, etc. (Figure 8, "B")	14.5'	15.0'	14.5'	15.0'	17.0'	17.0'	17.2'	17.7'	18.6'	19.1'	19.5'	20.9'	23.2			
Exception to Rules 1 and 2 above:	Since 1984, Rules do not apply to insulated services over 10' horizontally from edge of pool, platforms, etc.															

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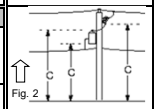
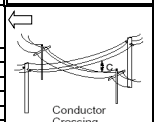


Fig. 2



Conductor Crossing
Fig. 3

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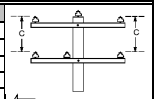


Fig. 4

234

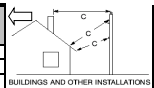
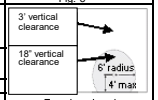


Fig. 5



Top view of roof

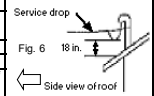


Fig. 6
Side view of roof

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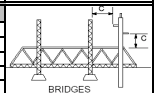

Fig. 7

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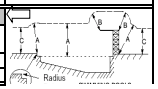

Other Clearances or Requirements.

1. Minimum vertical clr between communication cable of different companies is 4" NESC Rule 235H.
2. If a drip loop of conductors entering a luminaire or traffic signal bracket from the surface of structure is above communication cable, the lowest loop shall be 12" above communication cable or through bolt. It can be reduced to 3" if covered with non-metallic covering and extends into bracket 2".
3. Minimum vertical clearance between power supply lines & communication cable mid-span carried on same supports is 30". NESC Rule 235C2b(1)(a)
4. Horizontal clearance from structure to side walk curb - 6" (PacifiCorp recommended 18")
5. Conductors 0 - 300 V attached to the side of a building and/or run alongside the building shall have clearances not less than 3" since 2002, and one inch clearance for 1981-2001.
6. Horizontal clearance from structure to fire hydrant - 4'. Exception: allows 3' if 4' is not attainable. (Pre 2002: 3')

NESC: C=4' D=6" **PacifiCorp**: D=18"

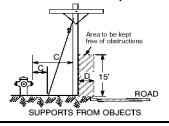

Fig. 9 SUPPORTS FROM OBJECTS

Fig. 8

A. 12' (10.5' if building height does not permit) (Pre 1977: 10' and 8')
B. 3' min. around doors, fire escapes, etc. (not readily accessible to pedestrians) 3' min. below or beside unguarded openable windows. (Since 1984)
C. 12" between communication wire and service wire. (Since 1981)
D. 40" between communication wire and service wire at service pole (12" if this is a meter pole).
E. 40" between communication wire and service wire at support structure.
F. 16' over driveway (See Grandfather Matrix for exceptions).
G. 18" or 3' drip loop to roof, see Fig. 6 above. See Matrix for exceptions. Pre 1977, no requirement.
H. 18.5' min. clearance above road for primary 750V-22kV.

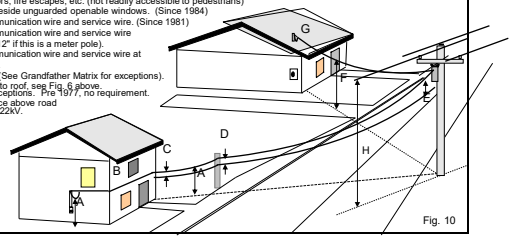

Fig. 10

PacifiCorp's Inspection Clearance Table ** (Do not use Table for construction, See Construction Standards)

All distances are minimums required by the NESC at worst conditions for **Transmission between 3301' - 9300' elevation.**

For more details see Transmission standards, section TC.

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Upper Level

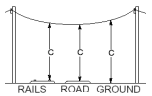


Fig. 1

		Elevation - 3301 to 6300 ft. Open Supply Conductors						Elevation - 6301 to 9300 ft. Open Supply Conductors					
		42 kV to 70kV phase-to-ground 115 kV phase-to-phase (ft.)	70 kV to 84 kV phase-to-ground 138 kV phase-to-phase (ft.)	84 kV to 98 kV phase-to-ground 161 kV phase-to-phase (ft.)	98 kV to 140 kV phase-to-ground 230 kV phase-to-phase	140 kV to 210 kV phase-to-ground 345 phase-to-phase	210 kV to 318 kV phase-to-ground 500 kV phase-to-phase	42 kV to 70kV phase-to-ground 115 kV phase-to-phase (ft.)	70 kV to 84 kV phase-to-ground 138 kV phase-to-phase (ft.)	84 kV to 98 kV phase-to-ground 161 kV phase-to-phase (ft.)	98 kV to 140 kV phase-to-ground 230 kV phase-to-phase	140 kV to 210 kV phase-to-ground 345 phase-to-phase	210 kV to 318 kV phase-to-ground 500 kV phase-to-phase
Ground Clearance - Where wires, conductors, or cables crossover or overhang													
1	Track rails of railroad (except electrified railroads using overhead trolley conductors	28.2'	28.8'	29.3'	30.8'	33.3'	37.3'	28.4'	28.9'	29.5'	31.1'	33.9'	38.1'
2	Roads, streets, and other areas subjected to truck traffic.	20.2'	20.8'	21.3'	22.8'	25.3'	29.3'	20.4'	20.9'	21.5'	23.1'	25.9'	30.1'
3	Driveways, parking lots, and alleys	20.2'	20.8'	21.3'	22.8'	25.3'	29.3'	20.4'	20.9'	21.5'	23.1'	25.9'	30.1'
4	Other land traversed by vehicles, such as cultivated, grazing, forest, orchard, etc.	20.2'	20.8'	21.3'	22.8'	25.3'	29.3'	20.4'	20.9'	21.5'	23.1'	25.9'	30.1'
5	Spaces and ways subject to pedestrians or restricted traffic only.	16.2'	16.8'	17.3'	18.8'	21.3'	25.3'	16.4'	16.9'	17.5'	19.1'	21.9'	26.1'
Vertical Clearance - Conductors & cables on different supports								Upper level					
1	Insulated com. conductors; messengers; surge protection wires; grounded guys; ungrounded guys exposed to 0-300 V; neutral conductors meeting Rule 230E1; supply cable needing Rule 230C1	3.7'	4.3'	4.8'	6.3'	8.8'	12.8'	3.9'	4.4'	5.0'	6.6'	9.4'	13.6'
2	Non insulated communication conductors; supply cables of 0-750 V meeting Rules 230C2 or 230 C3	7.7'	8.3'	8.8'	10.3'	12.8'	16.8'	7.9'	8.4'	9.0'	10.6'	13.4'	17.6'
3	Supply cable over 750V meeting Rules 230C2 or 230C3; open supply conductors, 0-750 V; ungrounded guys exposed to 300-750 V	3.7'	4.3'	4.8'	6.3'	8.8'	12.8'	3.9'	4.4'	5.0'	6.6'	9.4'	13.6'
4	Over 750V to 22kV to ground (34.5 kV to phase)	3.7'	4.3'	4.8'	6.3'	8.8'	12.8'	3.9'	4.4'	5.0'	6.6'	9.4'	13.6'
5	Over 22 kV to 27 kV to ground (46 kV to phase)	3.9'	4.4'	4.9'	6.5'	9'	12.9'	4.1	4.6	5.2	6.8	9.6	13.8
6	Over 28 kV to 42 kV to ground (69 kV to phase)	4.4'	4.9'	5.4'	7.0'	9.5'	13.4'	4.6'	5.1'	5.7'	7.3'	10.1'	14.3'
7	Over 42 kV to 70 kV to ground (115 kV to phase)	5.5'	6.0'	6.5'	8.0'	10.6'	14.5'	5.8'	6.3'	6.9'	8.5'	11.3'	15.5'
8	Over 70 kV to 84 kV to ground 138 kV to phase)	--	6.5'	7.0'	8.5'	11.1'	15.0'	--	6.9'	7.4'	9.1'	11.8'	16.1'
9	Over 84 kV to 98 kV to ground (161 kV to phase)	--	--	7.5'	9.0'	11.6'	15.5'	--	--	8.0'	9.6'	12.4'	16.6'
10	Over 98 kV to 140 kV to ground (230 kV to phase)	--	--	--	10.6'	13.1'	17'	--	--	--	11.3'	14.0'	18.3'
Vertical Clearance - Between conductors on the same supports													
1	**Communication Conductors & Cables**												
a	Located in Communication Space	49"	55"	61"	80"	110"	157"	50"	57"	63"	83"	116"	167"
b	Located in Supply Space	49"	55"	61"	80"	110"	157"	50"	57"	63"	83"	116"	167"
2	**Open Supply Conductors & Cables**												
a	Open conductors 0 to 750 V; Supply Cable meeting Rule230C1,2,or3; Neutral cond. Rule 230E1.	42"	48"	54"	72"	103"	150"	42"	49"	56"	75"	109"	160"
b	750V to 8.7 kV	45"	51"	58"	76"	106"	153"	46"	53"	60"	79"	112"	163"
c	Over 8.7 kV to 22 kV to ground	50"	57"	63"	81"	111"	159"	52"	58"	65"	85"	118"	169"
d	Over 22 kV to 27 kV to ground (46 kV to Phase)	54"	60"	66"	84"	115"	162"	55"	62"	68"	88"	121"	172"
e	Over 27 kV to 42 kV to ground (69 kV to Phase)	59"	65"	71"	90"	120"	167"	61"	68"	75"	94"	127"	178"
f	Over 42 kV to 70 kV to ground (115 kV to Phase)	72"	78"	84"	103"	133"	180"	75"	82"	89"	109"	142"	193"
g	Over 70 kV to 84 kV to ground (138 kV to Phase)	--	84"	91"	109"	139"	186"	--	89"	95"	115"	148"	199"
h	Over 84 kV to 98 kV to ground (161 kV to Phase)	--	--	97"	115"	146"	193"	--	--	102"	122"	155"	206"
i	Over 98 kV to 140 kV to ground (230 kV to Phase)	--	--	--	133"	164"	211"	--	--	--	142"	175"	226"
j	Over 140kV to 210kV to ground (345kV to Phase)	--	--	--	--	194"	241"	--	--	--	--	208"	259"
Clearances of Wires, Conductors and Cables, & Unguarded Rigid Live Parts - Adjacent but Not Attached to Buildings & Other Installations Except Bridges. No Wind													
1	**Buildings**												
	Horizontal to Walls, projections and guarded windows,	9.3'	9.8'	10.4'	11.9'	14.4'	18.3'	9.4'	10.0'	10.6'	12.3'	15.0'	19.2'
	Vertical over or under roofs or projections not readily accessible to pedestrians	14.3'	14.8'	15.4'	16.9'	19.4'	23.3'	14.4'	15.0'	15.6'	17.3'	20.0'	24.2'
	Vertical to decks, balconies, roofs, etc., accessible to pedestrians, and over roofs not accessible to trucks	15.3'	15.8'	16.4'	17.9'	20.4'	24.3'	15.4'	16.0'	16.6'	18.3'	21.0'	25.2'
	Vertical over roofs accessible to trucks	20.3'	20.8'	21.4'	22.9'	25.4'	29.3'	20.4'	21.0'	21.6'	23.3'	26.0'	30.2'
2	**Signs, chimneys, billboards, radio and television antennas, tanks, and other installations not classified as buildings or bridges**												
	Horizontal	9.3'	9.8'	10.4'	11.9'	14.4'	18.3'	9.4'	10.0'	10.6'	12.3'	15.0'	19.2'
	Vertical over or under	9.8'	10.3'	10.9'	12.4'	14.9'	18.8'	9.9'	10.5'	11.1'	12.8'	15.5'	19.7'
3	**Other supporting structures, wires, conductors, or cables of one line passing near lighting support, traffic signal support, or a supporting structure of a second line, not attached**												
	Horizontal	6.6'	7.3'	7.9'	9.4'	11.9'	15.8'	6.9'	7.5'	8.1'	10.1'	13.1'	17.6'
	Vertical	6.3'	6.8'	7.4'	8.9'	11.4'	15.3'	6.4'	7.0'	7.6'	9.3'	12.0'	16.2'
4	Vertical clearance to service (0 - 750 V), not readily accessible to pedestrians, that meets or terminates at a through-the-roof support & does not cross more than 6' of roof or is 4' or less from the roof edge shall be 18 inches. * See Distribution Standard DC-151 page 5.												
Clearances of Wires, Conductors and Cables From Bridges													
1	**Clearance over bridges.**												
a.	Attached	7.3'	7.8'	8.4'	9.9'	12.4'	16.3'	7.4'	8.0'	8.6'	10.3'	13.0'	17.2'
b.	Not attached	14.3'	14.8'	15.4'	16.9'	19.4'	23.3'	14.4'	15.0'	15.6'	17.3'	20.0'	24.2'
2	**Clearance beside, under or within bridge structure**												
a.	Readily Accessible portion of bridge												
	Attached	7.3'	7.8'	8.4'	9.9'	12.4'	16.3'	7.4'	8.0'	8.6'	10.3'	13.0'	17.2'
	Not attached	9.3'	9.8'	10.4'	11.9'	14.4'	18.3'	9.4'	10.0'	10.6'	12.3'	15.0'	19.2'
b.	Ordinarily inaccessible portions of bridge												
	Attached	7.3'	7.8'	8.4'	9.9'	12.4'	16.3'	7.4'	8.0'	8.6'	10.3'	13.0'	17.2'
	Not attached	8.3'	8.8'	9.4'	10.9'	13.4'	17.3'	8.4'	9.0'	9.6'	11.3'	14.0'	18.2'
Clearances of Wires Conductors and Cables Over Or Near Swimming Pools													
1	Clearance in any direction from the water, edge of pool, or base of diving platform. (Figure 8, "A")	26.8'	27.3'	27.9'	29.4'	31.9'	35.9'	26.9'	27.5'	28.1'	29.8'	32.5'	36.7'
2	Clearance to diving platform, tower, etc. (Figure 8, "B")	18.8'	19.3'	19.9'	21.4'	23.9'	27.8'	18.9'	19.5'	20.1'	21.8'	24.5'	27.8'

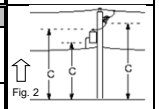


Fig. 2

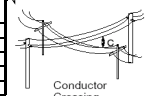


Fig. 3

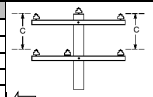


Fig. 4

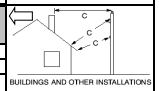
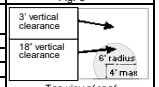


Fig. 5



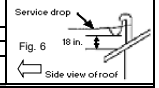


Fig. 6

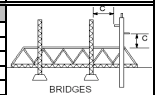
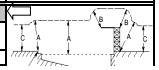


Fig. 7



Exception to Rules 1 and 2 above:	Since 1984, Rules do not apply to insulated services over 10' horizontally from edge of pool, platforms, etc.

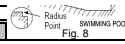
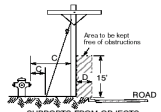


Fig. 8

Other Clearances or Requirements.

1. Minimum vertical clr between communication cable of different companies is 4" NESC Rule 235H.
2. If a drip loop of conductors entering a luminaire or traffic signal bracket from the surface of structure is above communication cable, the lowest loop shall be 12" above communication cable or through bolt. It can be reduced to 3" if covered with non-metallic covering and extends into bracket 2".
3. Minimum vertical clearance between power supply lines & communication cable mid-span carried on same supports is
4. Horizontal clearance from structure to side walk curb - 6" (PacifiCorp recommended 18")
5. Conductors 0 - 300 V attached to the side of a building and/or run alongside the building shall have clearances not less than 3" since 2002, and one inch clearance for 1981-2001.
6. Horizontal clearance from structure to fire hydrant - 4'. Exception: allows 3' if 4' is not attainable. (Pre 2002: 3')

A. 12' (10.5' if building height does not permit) (Pre 1977: 10' and 8')
B. 3' min. around doors, fire escapes, etc. (not readily accessible to pedestrians) 3' min. below or beside unguarded openable windows. (Since 1984)
C. 12" between communication wire and service wire. (Since 1981)
D. 40" between communication wire and service wire at service pole (12" if this is a meter pole).
E. 40" between communication wire and service wire at support structure.
F. 16' over driveway (See Grandfather Matrix for exceptions).
G. 18" or 3' drip loop to roof, see Fig. 6 above. See Matrix for exceptions. Pre 1977, no requirement.
H. 18.5' min. clearance above road for primary 750V-22kV.



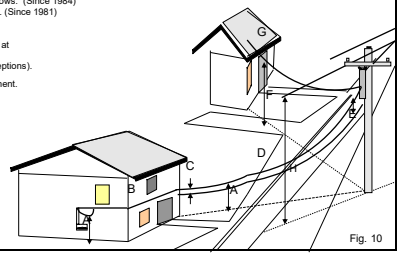


Fig. 10

NESC GRANDFATHERING

CITATION	NESC 2023	NESC 2017	NESC 2012	NESC 2007	NESC 2002	NESC 1997	NESC 1993	NESC 1990	NESC 1987	NESC 1984	NESC 1981	NESC 1977	NESC 1973	7th NBS Edition	6th NBS Editio
NESC Article 231A, Clearance between poles and **fire hydrants:**															
1. Minimum clearance of 4 feet (exception: 3 feet if 4 feet cannot be attained)	←←←	←←←	←←←	←←←	Adopted										
2. Minimum clearance of 3 feet (recommended clearance of 4 feet)						←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted
NESC Article 232, Table 232-1, Vertical Clearance limited to conductors at 0 to 150 V to ground for spaces and ways subject to **pedestrians** or restricted traffic only (Areas where riders on horses or other large animals, vehicle or other mobile units exceeding a height of 8 feet are prohibited by regulation or permanent terrain configurations, or are otherwise not normally encountered nor reasonably anticipated):															
Minimum clearance of 12 feet for conductors 0 to 150 V to ground (including drip loops) with the followin exceptions:	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted			
A. Exception: 10 feet minimum clearance for conductors meeting Rule 230C1 or 230C3 or drip loops onl meeting rule 230C3	←←←	Adopted													
B. Exception: Minimum clearance of 10 feet for conductors and drip loops 0 to 150 V to ground where building height does not allow 12 feet.			←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted			
C. Exception 1961 - 1976: Minimum clearance of 10 feet, but 8 feet where the form of the building will not permit 10 feet.													←←←	←←←	Adopted
NESC Article 232, Table 232-1, Vertical Clearance of service conductors to **driveway** for conductors 0 to 150V to															
1. Minimum clearance of 16 feet, but 12 feet for conductors and 10 feet for drip loops 0 to 150 V to ground where vehicles exceeding 8 feet in height are not normally encountered or resonably expected.	←←←	Adopted													
Minimum clearance of 16 feet, but 12 feet for conductors and 10 feet for drip loops 0 to 150 V to ground where building height does not allow			←←←	←←←	←←←	←←←	←←←	Adopted							
A. Exception: Where service conductors cross over or run along alleys, driveways or parking lots not subject to truck traffic (vehicles at least 8 feet in height), the clearance may be reduced to 15 fee	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted							
2. Minimum clearance of 10 feet for conductors and drip loops.									←←←	←←←	←←←	←←←	←←←	←←←	Adopted
NESC Article 234-E, Clearance from **swimming pools (Inground or Permanently Installed Above Ground)-** (does not apply if enclosed by solid or screened permanent structure):															
1. Service conductors 0-750V, clearance of 22.5 feet in any direction between conductors and pool, 14.5 feet to platforms, slides, etc.	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted							
Exception since 1987: Does not apply to ~~service~~ supply conductors more than 10 feet horizontally from the edge of the pool, platforms, etc	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted						
2. Open supply conductors 0-22kV, clearance of 25 feet in any direction between conductors and pool, 17 feet t platforms, slides, etc.	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted							
3. Service conductors, clearance of 18 feet in any direction to pool, 14 feet to platforms, slides, etc.	←←←								←←←	←←←	←←←	Adopted			
4. Open supply conductors 0-15kV, clearance of 25 feet in any direction to pool, 16 feet to platforms, slides, etc.	←←←								←←←	←←←	←←←	Adopted			
NESC Article 234C3d, Clearance from service conductors (0-750V) to **roof, deck or balcony:**															
1. Inaccessible deck, balcony or roof, minimum clearance of 3 feet to service conductors (1990-1992: 2 feet) (Prior to 1977, no clearance requirement for insulated conductors, however, insulation cannot be rubbing/abrading on building. Exception, from 1977 through 1992: If a service drop terminates at a support mast located not more than 4 feet horizontally from the nearest edge of the roof, the service drop may be maintained at a minimum of 18	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted			
								←←←	←←←	←←←	←←←	Adopted			
B. Exception, 1993 to present: If a service drop terminates at a support mast located not more than 4 feet horizontally from the nearest edge of the roof, the service drop may be maintained at a mimimum of 18 inches to the roof for 6 feet horizontally out from the mast, and then must be maintained at a minimum of 3 feet clearance above the roof thereafter. (2017 NESC page 126, Figure 234-2.)	←←←	←←←	←←←	←←←	←←←	←←←	Adopted								
2. Accessible deck, balcony or roof, minimum clearance of 10 feet to service drop conductors.	←←←	←←←	←←←	Adopted											
3. Accessible deck, balcony or roof, minimum clearance of 8 feet to service drop conductors.					←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted			
NESC Article 234C 3d2, Clearance to **window** for service drops (240/120V meeting rule 230C3):															
1. Service drop is above any window (openable or non-openable) or is below a non-openable window - there is no	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted					
NESC Article 235C1 Exception 3, Clearance between **service drop** (0-750V) **and communication drop:**															
1. The minimum clearance is 12 inches on service mast since 1981. No requirement prior to 1981.	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted				
NESC Article 215-C-2, Grounding or Insulating **Guys within 8 feet of the earth:**															
1. Guys that are attached to a pole with energized conductors of any voltage must be effectively grounded a specified in Rule 092C2 or have an insulator installed that that limits the likelihood of the anchor guy becoming energized within 8 feet of the ground.	←←←	←←←	←←←	Adopted											
2. Guys that are attached to a pole with conductors over 300V must have a guy insulator(s) or be effectively grounded to the neutral or pole ground.					←←←	←←←	←←←	←←←	←←←	←←←	←←←	Adopted			
3. Guys that are attached to a pole with conductors of 300V to 15kV must have a guy insulator(s) or be effectively grounded to the neutral or pole ground.													←←←	←←←	Adopted

HOW TO USE THIS MATRIX TO IDENTIFY GRANDFATHERED INSTALLATIONS:

Identify the applicable code and the adopted date on the matrix above.

Use year of pole installation, house vintage, or other hints to determine the approximate year the installatio originated.

If the installation appears to have previously met a prior existing code, enter it as a **Priority "G"** in the handheld.

HOW TO TREAT NATIONAL ELECTRIC CODE (NEC) DEFECTS:

Customer facilities are required to be compliant with the NEC, which is administered by the local electrical inspector. If you identify a defect of the NEC that is an immediate danger to the public, notify the local electrical inspector.

OLDEST APPLICABLE NESC EDITION FOR OVERHEAD AND UNDERGROUND LINES:
Due to verbage in prior editions of the NESC, the oldest version that can be grandfathered is the 6th Edition issued in 1961.
Any equipment installed prior to 1961 must at the minimum meet the rules detailed in the 1961 edition, prior editions cannot be grandfathered.

NEC defects should only be input into FPI as notes on the "IF" screen to describe the situation.

An example of a NEC defect is a service mast of greater than 4' that is not guyed (NEC Article 230.28).

CALIFORNIA GO 95 - GRANDFATHERING

CITATION	GO95 2009	GO95 2006	GO95 2002	GO95 1997	GO95 1992	GO95 1990	GO95 1988	GO95 1984	GO 95	GO95 1962	GO95 1942	
GO95 Rule 51.6-A: High Voltage Marking Signs on Poles where conductors are not on Crossarms:												
1. Poles which support conductors of more than 750 volts shall be marked with high voltage signs.	←	←	←	←	←	Adopted						
2. Poles supporting conductors of 750 volts to 20,000 volts shall be marked with high voltage signs.							←	←	←	←	←	Adopted
GO95 Table 1, Case 4, Column D: For open supply conductors 0-750V, clearance above ground along thoroughfares in rural districts or across other areas capable of being traversed by vehicles and agricultural equipment:												
1. Minimum clearance 19 feet.	←	←	←	←	Adopted							
2. Minimum clearance 16 feet.						←	←	←	←	←	←	Adopted
GO95 Rule 54.4-A(2)a, Table 1, Case 3, Column E: For conductors 750V to 22,500V, clearance above ground crossing or overhanging traversable portions of roads or driveways:												
1. Minimum clearance 25 feet.	←	←	←	←	Adopted							
2. Minimum clearance of 22 feet.						←	←	←	←	←	←	Adopted
GO95 Rule 54.4-A(2)b, Table 1, Case 4, Column E: Clearance above ground for lines 750V to 22,500V across areas capable of being traversed by agricultural equipment and along roads where no part of the line overhangs any traversable portion of roadway:												
1. Minimum clearance 25 feet.	←	←	←	←	Adopted							
2. Minimum clearance of 18 feet.						←	←	←	←	←	←	Adopted
GO95 Rule 54.8-D1, Table 1, Case 10, Column D: For service drops 0 - 750V, clearance from non-climbable street lighting poles and traffic signal poles or standards:												
1. Service drops passing unattached shall clear non-climbable street lighting and traffic signal poles, or standards including mastarms, brackets and lighting fixtures, a radial distance of 12 inches, except when the conductors are mechanically protected from abrasion 15 inches each direction from the cable centerline. (Prior to 1980 the code was silent on this.)	←	←	←	←	←	←	←	←	Adopted			

HOW TO USE THIS MATRIX TO IDENTIFY GRANDFATHERED INSTALLATIONS:

Identify the applicable code and the adopted date on the matrix above.

Use year of pole installation, house vintage, or other hints to determine the approximate year the installation originated.

If the installation appears to have previously met a prior existing code, enter it as a **Priority "G"** in the handheld.

HOW TO TREAT NATIONAL ELECTRIC CODE (NEC) DEFECTS:

with the GO95. Customer facilities are required to be compliant with the NEC, which is administered by the local electrical inspector. If you identify a defect of the NEC that is an immediate danger to the public, notify the local

NEC defects should only be input into FPI as notes on the "IF" screen to describe the situation.

No.	Group	NESC Issue	Resolution	Ref	Co. Code
2	CATV/TELCO/FIBER	What condition should be used for J hooks?	J hooks owned by other companies should use Incomplete Changeover/Transfer		
3	Clearance	Can a pole step or stand off bracket be installed on a pole in the first 8' if there is 8' clearance from the first step to the next device?	An 8-foot space is required to prevent someone from climbing a pole. If there is a standoff bracket within the first 8 feet, then there must be a separation of 8 feet to the next step.	217A-2	COOTHER
4	Clearance	What is the clearance for services over hot tubs in yards or on decks?	11 foot clearance to service wires. See both paragraphs in "Note" in 234-E-1.	234-E-1 Note Table 234-1	
5	Clearance	Does the NESC require 3 feet clearance from a window that cannot be opened?	A 3ft. clearance is required from drip loops and conductors in any direction from doors, porches, fire escapes or similar locations. Windows that have a sliding and fixed pane, the 3 ft requirement applies to the sliding portion of the window. If a window is not designed to open there is no clearance requirement.	234C3d(2)	
6	Clearance	Does the NESC require 3 feet clearance from a window for buildings built prior to 1984?	3 ft. minimum clearance is required around unguarded windows, door, and fire escapes. There was no clearance requirement for windows prior to 1984, so installations before 1984 are grandfathered.	234C3d2	
7	Clearance	For services less than 300 Volts over residential buildings, is the clearance over the roof grandfathered at some time?	The service mast must be located not more than 4' from the nearest edge of the roof, measured horizontally. If the mast is installed more than 4' from the nearest edge of the roof or the service crosses over more than 6' of the roof, after a horizontal distance of 6' a vertical clearance of 3' min is required over the remainder of the roof. The vertical clearance within the 6' radius of the service mast is 18". From 1977 until 1993 the clearance was 18" within 4' of the edge of the roof and no mention was made of the 6' radius. Before 1977 there were no clearance requirements over the roof for insulated services up to 750V.	Rule 234C3d exception 2	
8	Clearance	What is the required communication clearance from a span guy that has secondary attached to it and doesn't have the proper "J" ball or insulator installation?	Proper installation is as follows: NESC states that for 300V or less, if there is 1 J-ball it should be on the power end of a span guy and if there are 2 J-balls there should be one on each end of the span guy. The required clearance is 40" at the pole and 30" at midspan.	table 235-5 section 1a for clearance at the pole and 235C2b1a for the midspan	
9	Clearance	What is the required communication clearance from a span guy that has secondary attached to it and a "J" ball or insulator installed in both ends?	The required clearance is 40" at the pole and 30" midspan, the same as the clearances for an attachment.	table 235-5 section 1a for clearance at the pole and 235C2b1a for the midspan	
10	Clearance	When midspan height conditions are captured, how are these tied to a specific facility point?	The condition can be tied to the pole on either side, however the inspector should indicate on the IF screen that the condition is between FP#XX and FP#YY.		
11	Clearance	For services less than 150 volts to ground over driveways, is the clearance over the driveway grandfathered at some time?	For installations from 1990 through 2006, the clearance is still 16', but can be as low as 12' (10' for the drip loop) if the building height does not allow higher. From 1941 through 1989, the clearance is 10 feet.	Rule 232, Table 232-1	
12	Clearance	For conductors over swimming pools, is the clearance grandfathered at some time?	From 1977 through 1989, insulated service conductors 0 to 750 volts have a clearance of 18 feet in any direction from the pool, and 14 feet to platforms, water slides, etc., and open supply conductors 0-15kV have a clearance of 25 feet in any direction between conductors and the pool, and 16 feet to platforms, water slides, etc. The is no reference to swimming pools prior to 1977.	Rule 234-E	
13	Clearance	For services 0 - 750 volts to ground over decks, balconies and roofs accessible to pedestrians, is the clearance grandfathered at some time?	For installations from 1977 through 2006, the clearance is 8 feet.	Rule 234-C-3-d	
14	Climbing space	Are bolts protruding more than 4" a condition?	Thru-bolts are condition only if 4" beyond nut and in the only available climbing space	Rule 236E	COCATV COFIBER COTELCO
15	Climbing space	Are messenger bonds considered a condition in the climbing space if all other wires/lines are on the opposite side of pole?	Yes, all horizontal runs of wire in the climbing space are considered to be non-conforming.		COOTHER
16	DTLTRT	Should a DTLTRT be performed on Qwest poles?	There are agreements in some areas that allow for PTT and billing the pole owner. This is area specific. If the pole is not to be treated, perform a detail inspection.		
17	Fence	Are fences attached to poles a condition?	A fence should be reported as a condition only if there is not adequate spacing to prevent being used as a step to climb the pole.	217-2	COOTHER, COCATV, COTELCO
18	FPI	If a condition exists in FPI and a second inspection shows the same condition, is it necessary to add the condition a second time?	The condition only needs to be input into FPI once. If further explanation is needed note this in the IF screen, and if the condition has worsened it can be changed to higher priority.		IF
19	FPI	What should be done with facility points that are unable to be inspected due to access and customer issues?	If an inspector is not able to inspect a transmission facility because it is inaccessible because there's no road or impassable, the inspector should input CANTINSP into FPI for the facility point. If it's on a distribtuion facility and because of locked gate or no access, the inspector should input ~~CUSTRESP~~ CANTINSP into FPI and create an IF code to record the address and note the issue. District should identify these points and make arrangements for permanent access.		CANTINSP or CUSTRESP
20	Ground	Are all ground rods out of ground to be reported, even communication ground rods?	All Ground rods out of ground must be reported, including communication company ground rods. Ground rods above ground are an NESC condittion. NESC requires 8' of rod in the soil. Note on IF screen if ground rod is from a JU licensee.	94B2-C	BOGRD

21	Ground	Is there a stores number for ground clamps used to ground steel conduit? Is a copper band or plumbers tape an acceptable means of grounding?	There is a standard clamp for grounding these conduits. GC 851. The SI # 5310611		
22	Ground	Is there a specific position to ground the conduits?	All grounding should be installed per company standard, 2-3" below grade.		
23	Ground	When locates are performed on poles often times the straps are popped out by the locators. Can this be corrected?	If the ground "strap" is disconnected it needs to re-connected by a qualified electrical worker.		
24	Ground	Does a customer ground rod above ground level need to be reported if they are on our pole?	All ground rods above ground level are NESC conditions. Report high customer ground rod on company facilites as BOGRD and note in IF screen that it is customer owned.		BOGRD
25	Ground	Is a riser that is grounded below the surface (and therefore cannot be seen to be verified) a condition?	No, company standards call for risers to be grounded below the surface		
26	Guy or Anchor	How should down guys and anchors attached to a PacifiCorp facility on a licensee-owned anchor be inspected?	Guys installed since 1977 that are within 8' of the earth and are attached to a pole with conductors above 300V (and also below 300V since 2007) must have a guy insulator or be effectively grounded to the neutral/pole ground. Input into FPI as COTELCO or COCATV if there are NESC conditions on the JU guy or anchor.	215-C-2	
27	Guy or Anchor	How should cable TV and TELCO guys attached to PacifiCorp anchors using auxiliary or sister eyes be inspected?	Sister eyes are not acceptable and are a condition COTELCO or COCATV. JU Department will coordinate with licensee to correct the problem by having licensee install their own anchor.	EU101	COTELCO COCATV
28	Guy or Anchor	How are foreign guys to be addressed?	Foreign guys have been allowed on PacifiCorp installations in the past. In all cases the anchor must be adequate to support the load. If there are no visible problems with the anchor, it is not a condition. If down guy is slack and anchor is "pulling," report as a condition COTELCO or COCATV.		COTELCO COCATV
29	Guy or Anchor	How should cable TV and TELCO Anchors attached to PacifiCorp anchors or double head anchors that are visibly bonded be inspected?	This does not meet PacifiCorp standards and is a correctable condition. Anchor must be adequate to support the load. Bonding of down guy is issue. JU department will coordinate the repair with the licensee responsible.		COCATV COTELCO
30	Guy or Anchor	Is Osmose to install guy markers on PacifiCorp anchors and licensee anchors?	Yes, install guy markers on all down guys, except marker not required if guy that is not in pedestrian or traffic area is engulfed in dense vegetation or is otherwise inaccessible.		BOGUY
31	Guy or Anchor	Should tails on TELCO and CATV anchors be clipped?	Clip tails on all guy wires that extend out of grip.		COTELCO COCATV
32	Guy or Anchor	Are slack guys to be reported?	Slack guys are to be reported per Policy 009, Section 3.3., only if pole is not in proper vertical position.		BOGUY
33	Guy or Anchor	Should guy markers be installed on all down guys attached to a single anchor?	Yes. Down guys are to have a guy marker installed per company standard. Marker not required if guy that is not in pedestrian or traffic area is engulfed in dense vegetation or is otherwise inaccessible.		
34	Guy or Anchor	Do we install guy markers on all down guys attached to multiple anchors in the same plane?	Yes. Down guys are to have a guy marker installed per company standard. Marker not required if guy that is not in pedestrian or traffic area is engulfed in dense vegetation or is otherwise inaccessible.		
35	Guy or Anchor	What is the position of a guy insulator if there is no communications attached to the pole?	If down guy breaks, insulator must be at least 8 ft above ground. On transmission with distribution underbuild the insulator is to be positioned to land so guy cannot energize distribution.	EG 051	
36	Guy or Anchor	Should secondary down guy insulators below communication level be captured as a condition?	This is not a condition and should not be reported in FPI		
37	Guy or Anchor	Should down guys that cross over each other be captured?	This is not an NESC condition and should not be reported in FPI.		
38	Guy or Anchor	Are anchors extending out of the ground 12" non-conforming?	This is not an NESC issue and should not be reported.		
39	Joint Use	Are TELCO Pedestals within 3' of a pole a condition?	Because these are not NESC conditions, these should not be entered as such, but verify 8 ft. separation from the top of the pedestal to prevent climbing of the pole. Note the location of the pedestal in the IF screen.	217-2	IF
40	Joint Use	Can the pole be removed on JU non transfers?	Do not remove a pole on a JU non transfer by cutting the top and leaving it attached to the TELCO because this is a hazard.	214A-5	TELCO
41	Joint Use	What clearances should be reported for conductors passing by a facility point horizontally?	TELCO and CATV 3' for phase conductor and 5' for neutral conductor, measured horizontally.	234B	
42	Joint Use	TELCO conductors crossing over roadways that run pole to pole must be 15'6" over the road. Does this apply to TELCO service drops?	Yes, this does apply to TELCO service drops.		CLRTELCO
43	Pole	Do idle facilities need to be removed?	Idle facilities (pole with no equipment or wire) must be removed. A pole with a de-energized transformer or a de-energized tap line, etc, is not a condition and does not have to be removed but must be maintained.	214B-2 214B-3	COOTHER
44	Pole	How should woodpecker damage be reported in FPI?	Input as BIRDDMG. Exception: if damage is severe mark as BOPOLE.		BIRDDMG
45	Pole	Are dead end poles with no down guys reported as a condition?	Report if pole is leaning or needs additional support.		
46	Pole	How are old pole butts to be treated?	If the pole butt is in a rural area that is publicly inaccessible it is not a condition if it is cut off at or below ground level.		
47	Pole	How should leaning poles be addressed?	If leaning into roadway and an immediate hazard to vehicular traffic, A. If leaning severely in an urban area, A. If leaning moderately in urban area, B. Anchor pulled is BOANC. Pole deteriorated is BOPOLE. Pole cracked from stress is BOPOLE.		

48	Pole	On structure with a push brace what is treated?	On structure with a push brace the pole and the push brace are both treated. The facility point is only associated with pole. Make a notation on the IF screen that the push brace has been treated.		
49	Pole	Are customer meter bases on PacifiCorp poles allowed and if so, are they grandfathered?	These are not NESC conditions and should not be reported.		
50	Pole	What condition should be used for a leaning pole?	BOPOLE is used when the pole is leaning due to decay. BOANC is used when the anchor is pulled. BOGUY is used when a good pole needs a guy. COOTHER is used when the pole is leaning due to any other reason.		
51	Riser	Do all metallic communication risers on a pole have to be grounded?	Communications risers do not have to be grounded unless exposed to contact with open conductors of greater than 300V.	314.B	
52	Riser	On risers, how are broken conduits and split/separated joints to be addressed?	For both primary and secondary risers, with access, below 8 feet is an A condition, above 8 feet is a B condition.		
53	Satellite dish	What is the required clearance between a satellite dish on a roof top and an electrical service riser?	Although satellite dishes are not specifically mentioned, the NESC allows 12 inches at the served structure.	235C-1 Exception 3	CUSTRESP
54	Service	Can communications attach to a mast below a weatherhead?	Yes. Inspectors should verify that the communications is at least 12" below power conductor for installations since 1981. If not, this is an NESC condition and should be input into FPI. No requirements prior to 1981.	235C-1	CLRTELCO
55	Service	Mast over 4' must be guyed. Are these a condition if they are not guyed?	Mast guying is an NEC requirement, and was added to the code in 1975. All masts must be adequately supported or guyed to safely support the service cable. There is no height or guying requirement in the NESC. This should be reported as a condition in FPI only if the mast is being pulled or leaning.		BOSVCENT
56	Service	On a customer-owned meter pole do communication facilities or joint use attachments have to have 40" clearance?	All meter pole or service poles are considered the point of attachment so clearance requirements are the same as the point of attachment. The communication must be at least 12 in. below the power conductor.	235C-1	CLRTELCO CLRCATV
57	Sign	Are signs attached to poles a condition?	Traffic signs can be grandfathered. If signs are temporary such as garage sale or lost dog signs, please remove.		RWENRCH
58	Street/Area Light	What are the correct street light clearances?	If a drip loop of conductors entering a luminaire or traffic signal bracket from the surface of a structure is above the communication cable, the lowest loop shall be 12" above communication cable or through bolt. It can be reduced to 3" if covered with non-metallic conduit. The mast clearance is 20" if not grounded. This may be reduced to 4" if effectively grounded.	238C 238D	CLEAR
59	Street/Area Light	On customer-owned lights on a meter pole what is the clearance from the light to weatherhead?	Company must follow NESC. If installed on load side of meter installation must meet NEC. Nothing specific found on this type of installation in NEC. NESC guidelines for clearances may be applied.		CLEAR
60	Street/Area Light	On street lights are mounting holes with missing lag bolts a condition?	All hardware must be securely mounted to the structure, regardless of the number of bolts. If not securely mounted report as COOTHER.		COOTHER
61	Trees	Are trees that deflect a service a condition?	Service wire deflected or abraded by vegetation is a condition in Oregon only. Not a condition if guarded at point of deflection		CLEARSVC
62	Trees	If trees are pulling or pushing hard on communication lines in a midspan this could create pole integrity issues on either poles on each side; should these be captured if it can be determined that there is a possible	Report as COTELCO or COCATV. This should only be reported if condition is severe.		COTELCO COCATV

No.	Group	GO 95 Issue	Resolution	Ref	Comments and Notes
2	ABANDONED EQUIPMENT	How should abandoned *equipment* be addressed?	An abandoned item of equipment such as a transformer, switchgear unit, etc, is not nonconforming.	Rule 31.6	Input as a C condition
3	ABANDONED LINES	How should abandoned *lines* be addressed?	GO95 states that lines permanently abandoned shall be removed by their owners. "Permanently abandoned" is defined as those lines that are determined by their owner to have no foreseeable future use.	Rule 31.6	Applies to lines or sections of lines that do **not** go to any buildings, structures, facilities or developments that may need electrical service in the future. Enter as a C condition for further review by District.
4	ACCESS	What should be done with facility points that cannot be inspected due to access and customer issues?	If an inspector is not able to inspect a facility because it is inaccessible because there's no road or impassable, the inspector should input CANTINSP into FPI for the facility point. If it's because of locked gate or no access, the inspector should input CUSTRESP into FPI for the facility point and record the address. District should identify these points and make arrangements for inspection.		Enter as CANTINSP or CUSTRESP
5	CLEARANCE	Do secondary poles with communication attached need to have a guard arm installed for clearances?	No, 48 inches is acceptable unless it's open wire secondary in which case a guard would need to be installed or maintain 60 inches clearance.	Rule 54.8.G2C Rule 38, Table 2, Column D Rule 84.8B2b Rule 87.4C3 Paragraph 3 & Exception Rule 92.1-B	Standard EU 241
6	CLEARANCE	Are measurements at the pole for clearances between supply and communications to be taken from the point of attachment or should they be from wire to wire / hardware to wire?	Table 1 clearances apply for the entire length of all lines involved, including hardware. Table 2 applies to conductor crossings, midspan, and supports. Anything separated more than 5 inches at the pole will be measured centerline of conductor to centerline of conductor (lowest part of supply to highest part of communications).	Rule 37, Table 1 Rule 38, Table 2	
7	CLEARANCE	What is the required clearance from the transformer case to the secondary or neutral?	10 inch clearance to secondary, neutral or service is requred.	Rule 54.4G Rule 58.1E Table 58-2	
8	CLEARANCE	What is the required clearance for communication services above residential driveways?	12 feet is required. If the building cannot provide this clearance and the service is insulated, the clearance shall be as great as possible, but in no case less than 10 feet.	Rule 54.8B2(b) & Exception Training Guide page 15	
9	CLEARANCE	What is the required clearance for span wires and overhead guys above ground not accessible to vehicles?	8 feet is required.	Rule 86.4A1© Table 1 case 5A	
10	CLEARANCE	What is the required clearance for communication conductors and supply conductors of 750V or less crossing over communication not on the same supporting structure?	48 inches minimum is required.	Rule 54.8C1(a) Rule 54.8C4 Table 2 case 9C	
11	CLEARANCE	What is the required separation between supply service drops and communication service drops to a residence?	12 inches at attachment to building and 12 inches for first 15 feet from building. More than 15 feet from building requires 24 inch clearance.	Rule 54.8C4 Rule 84.8D4	
12	CLEARANCE	What is the required clearance between conductors not on the same support of 750V up to 7500V?	48 inches minimum is required.	Rule 38 Table 2, Case E5	
13	CLEARANCE	At a pole housing primary conductors, what is the required clearance at the pole between supply conductors of 0-750V and communication mounted on same pole *with* a guard arm?	For communications attached to the surface of the pole, the clearance is 72 inches, and can be reduced to 48 inches with a guard arm.	Rule 38 Table 2, case 8D Rule 84.8B2c Rule 87.4C3 Paragraph 3 Exception Rule 92.1-B	

14	CLEARANCE	At a pole housing primary conductors, what is the required clearance at the pole between supply conductors of 0-750V and communication mounted on same pole *without* a guard arm?	If communications is mounted on a crossarm, and is mounted more than 15 inches from the centerline of pole, then the clearance is 48 inches. But if less than 15 inches or if attached to the surface of pole, then 72 inches must be maintained.	Rule 38 Table 2, case 8D Rule 84.8B2b Rule 87.4C3 Paragraph 3 Rule 92.1-B	
15	CLEARANCE	What is the required clearance for supply and communication service drops over a street, alley or public thoroughfare?	18 feet clearance from centerline until at 12 feet horizontally from curb edge, then gradually reduced to 16 feet at curb edge.	Rule 84.8C(1) Exception	
16	CLEARANCE	What is the clearance from supply conductors 0-750V crossing supply conductors 0-750V on separate supports on the same pole?	24 inches minimum is required.	Table 2 case 9D	
17	CLEARANCE	What are the clearances for 0-750V supply service drops in midspan from communication conductors?	24 inches minimum is required, but can be 12 inches within 15 feet of the house.	Table 2 case 3D note (i) Rule 54.8C4	
17b	CLEARANCE	What are the clearances for 0-750V supply conductors in pole to pole midspan from communication conductors?	48 inches minimum is required. May be 36 inches midspan if supply is abrasion-resistant and neutral-supported.	Rule 57 and 54.10 Table 2, note pp	
18	CLEARANCE	What is the required hardware clearance on wood poles?	Shall have a clearance of not less than 1.5 inches	Rule 54.6H	
19	CLEARANCE	What is the required clearance for the lowest pole step above the ground line?	Lowest step shall not be less than 7.5 feet above ground line.	Rule 91.3B	
20	CLEARANCE	For 0 - 750 volt services, what is the minimum horizontal clearance from buildings, bridges or other structures that the service is not attached to?	3 feet is required.	Table 1 case 7B Table 10	
21	CLEARANCE	What is the required window clearance?	3 feet for service drops up to 750V; 6 feet for 750V to 300kV; 15 feet for 300kv to 550kV.	Rule 54.4-H-1 Table 1 case 7	
22	CLEARANCE	Can a communication service drop lay on the roof of the building being served?	Yes, communication service drops are not required to clear the roof of the building served by any specified vertical distance.	Rule 84.8-C4	
23	CLEARANCE	For a supply service drop, what is the required vertical distance from a building that the service drop is not attached to?	The vertical clearance above buildings on premises other than the one being served shall not be less than 8 feet, except that a reduction to not less than 2 feet is permitted under certain conditions outlined in Rule 84.8-C4a&b.	Rule 84.8-C4	
24	CLEARANCE	For communications, what is the required vertical distance from a building that the comm drop is not attached to?	The vertical comm clearance above buildings on premises other than the one being served shall not be less than 8 feet, except that a reduction to not less than 2 feet is permitted under certain conditions outlined in Rule 84.8-C4a&b.	Rule 84.8-C4	
25	CLEARANCE	What is the horizontal clearance for communications from buildings and other structures not attached?	Communication cables are not required to be any specified distance from the sides of buildings, bridges and other structures, but they shall be installed so that they do not interfere with the free use of fire escapes, windows, doors and other points at which entrance or exit might be reasonably expected.	Rule 84.4E Table 1 Case 7 Subnote "u"	
26	CLEARANCE	Can a communication conductor or messenger be attached to the top or side of a guard arm and still maintain 48 inches?	No. If on top, the communication conductor/cable/ messenger needs to have 72 inches of clearance. To reduce to 48 inches, communications shall be supported on or attached to bottom or side surface of any guard arm except as permitted for service drops and their vertical and lateral runs.	Rule 84.6C Rule 84.8B2c Rule 87.7-B	If communications is 2" below the top of guard arm or attached to bottom side, it may be reduced to 48" regardless of how far it is off the centerline of pole .

27	CLEARANCE	For communication cables and supply service drops, what is the vertical clearance required above signs upon which people cannot walk?	2 feet	Rule 39 Table 2-A (page III-32)	
28	CLEARANCE	For communication cables and supply service drops, what is the horizontal clearance from signs which are illuminated?	3 feet, but may be reduced to 6 inches provided illuminated sign is grounded.	Rule 39 Table 2-A (page III-32)	
29	CLEARANCE	When midspan height conditions are captured, how are these tied to a specific facility point?	The conditon can be tied to the pole on either side, however the inspector should also indicate the other pole's fp number.		
30	CLIMBING SPACE	Are bolts protruding more than 4 inches a conditon?	Report all bolts protruding more than 4 inches out from the nut as a condition if they are below a transformer, in the climbing space, or 30 inches or more below the primary.		Enter as COOTHER (COTELCO,COCATV,
31	COMM CLEARANCE	What is the required clearance for communication services above commercial driveways?	16 feet is required.	Rule 84.8C2(a)	
32	DEFINITIONS	What is the difference between weather-resistant, covered and insulated services?	*Weather resistant :* Equivalent to standard double braid weatherproofing. *Covered:* Protected, sheltered. *Insulated:* Having insulating material the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages.	49.4C7a 20.8-G	
33	EQUIP CLEARANCE	What is the required clearance for equipment cases above ground level?	Equipment cases above ground accessible to vehicles require 17 feet clearance; not accessible to vehicles there is no clearance requirement but shall be effectively grounded if less than 8 feet above ground.	Rule 58.1B(2)	
34	GROUND	Can ground wires be exposed if molding is cracked or has minor separation?	Ground molding may have minor separation, warping, or cracks, provided the ground wire is not exposed.	Rule 54.6-B	
35	GROUND RODS	Do communication ground rods need to be a minimum distance from the pole?	The driven ground rod shall be located 24 inches or more from the surface of the pole.	Rule 92.4C2(e)	
36	GROUND RODS	Are supply ground rods required to be below ground level?	The top of the ground rod can be above ground level. However, ground rods shall be driven into the ground so that one end of the ground rod is at a minimum depth of 8 feet below the surface of the ground.	Rule 59.4-A-2-c	
37	GROUND WIRE	Do ground wires attached to the bottom or face of a crossarm need to be covered?	All ground wires need to be covered in their entirety including the bottom and face of a crossarm.	54.6B	
38	GROUND WIRE	Are ground wires attached under the crossarm required to be covered by wood or high impact ground molding?	Both are acceptable, as is red hose, but only for under the crossarm.	Rule 22.2D	
39	GROUNDING	In a cluster mount arrangement, do transformer cases and/or racks need to be grounded?	There is no requirement for any rack to be grounded. On metal poles and metal structures, transformer cases must be bonded to the structure which must be grounded.	Rule 58.2A3 (Confirmed via CPUC correspondence of May 21, 2009)	

40	GUY CLEARANCE	What is the required clearance for supply and communication guys above industrial or commercial entrances?	16 feet is required.	Rule 86.4A1 Exception (a)	
41	GUY CLEARANCE	What is the required clearance for supply and communication guys above private residential entrances?	14 feet is required.	Rule 86.4A1 Exception (b)	
42	GUY OR ANCHOR	Is Osmose to install guy markers on PacifiCorp anchors and	Yes, per agreement Osmose will install guy markers on all guys.		Enter as condition and correct the condition in FPI.
43	GUY OR ANCHOR	Should guy tails on Telco, Fiber and CATV anchors be clipped?	Clip tails on all guy wires that extend out of strandvise.		Enter as COTELCO OR COCATV
44	GUY OR ANCHOR	Are slack guys to be reported?	Slack guys are to be reported as BOGUY for futher evaluation.	Rule 56.2 EG 091	Enter as GO95 GUY
45	GUYS	If there is no communication on pole, can there be a barrel of proximity?	Yes	Rule 56.6A Figure 56-3	
46	GUYS	Do communication down guys need to have an insulator installed or be bonded if attached to their through bolt?	They must be insulated and not grounded if they fall within Rule 56.6A barrel of proximity.	Rule 56.6A	
47	GUYS	Where should an insulator be installed in an *overhead* guy that is required to be sectionalized?	The insulator shall be installed not less than 6 feet and not more than 9 feet from the point of attachment to the pole, and shall be 8 feet minimum vertically above the ground.	Rule 21.3-D Figure 56-4b, 56-5, 56-6 Rule 56.7A Rule 86.7	For ungrounded OH guys that are less than 17 feet in length, a single insulator can be installed at about midpoint between the two supports. 56-7A
48	GUYS	Where should the insulator be installed in a *primary down* guy that is required to be sectionalized?	8 feet or more above the ground, and 8 feet or more below the level of the lowest supply conductor; or 6 feet or more from the surface of the pole and 1 foot or more below the level of the lowest supply conductor.	Rule 56.7B(1)(2) Figure 56-8	
51	HIGH VOLTAGE SIGNS	What are the requirements for "High Voltage" warning signs on poles not carrying equipment?	Poles supporting line conductors more than 750 volts shall be marked with "High Voltage" signs. Signs shall be located not more than 40 inches below the lowest line conductor, or shall be located on the face and back of the crossarm.	Rule 51.6A Figure 51-1	
52	HIGH VOLTAGE SIGNS	What are the requirements for "High Voltage" warning signs on poles that are carrying equipment such as energized transformers?	Same as above, but with the option to instead install a sign that approximately encircles the pole, and that is no more than six inches below the equipment and is above all communication line conductors and supply line conductors of 0-750 volts.	Rule 51.6A(Option 2)	
53	HIGH VOLTAGE SIGNS	What are the requirements for "High Voltage" warning signs on poles that do not support line conductors of more than 750 volts, but that do support risers of more than 750 volts?	The top of the sign must be located below the top of the riser but no more than 40 inches below the top of the riser.	Rule 51.6A	For example, this may occur in agricultural areas where an UG primary feed goes up a riser to an OH transformer that feeds secondary OH to a pump house, for better visibility.

54	MISC	Are foreign attachments allowed on poles (signs, customer signs)?	Foreign attachments are only allowed with the consent of both the utility owner and the Commission.	Rule 34 Rule 15.1	
55	MISC	Do multiconductor cables from different secondary source feeds need to have separate attachments?	Secondary of multiconductor cables being fed from different secondary sources shall have separate attachments (i.e. spools, dead ends, racks).	Rule 54.10-C(6)	
56	MISC	Do vertical communication attachments above ground level need to be securely attached?	Vertical runs shall be treated as risers where within 8 feet from the ground line. Above 8 feet all vertical communication runs not installed in conduit or covered must be supported no more than every 24 inches by bridle hooks or rings.	Rule 87.7D Rule 84.6D	
57	MISC	What is the deciding factor for determining Urban vs Rural designation?	100% of Pacific Power's service area in California is Rural per agreement with the CPUC.		
58	NEUTRAL MARKING	Does the neutral need to be marked if located in the primary position?	Yes, a common neutral in the primary position needs to be marked as "CN". Those not in the primary position do not.	Rule 59.3E3 Rule 59.3F	
60	POLE	How should woodpecker damage be reported in FPI?	Input as "BIRDDMG". Enter as B condition per Policy 045.	PacifiCorp Woodpecker Policy 045	Enter as BIRDDMG
61	POLE	Are dead end poles with no down guys reported as a condition?	Report if the pole is leaning excessively or needs additional support.		
62	POLE	On structures with a push brace, what is treated?	On structures with a push brace, the pole and the push brace are both treated. The facility point is only associated with the pole. Make a notation on the IF screen that the push brace has been treated.		
63	POLE	Do communication risers including service drops running down the pole need to be covered?	Per GO 95, communication risers shall be covered to at least 8 feet above ground level.	Rule 87.7D1(a)	BORISER - A priority if below 8 ft and B if above 8 ft.
64	POLE	Are stand-off brackets located at the bottom of a riser nonconforming?	No, this is not nonconforming.		
65	POLE	What is the required separation between staples for all covered parts of vertical run attachments including communication and ground wires?	Maximum spacing 3 feet, but locate extra staples as required to follow contour of pole.	Rule 22.2 Figure 82	
66	POLE	Are all supply service drops required to be attached to an insulator or house knob?	Yes, all service drop cables with a bare neutral conductor must be attached at the pole and the building ends by means of an insulator.	49.4-C-7-a	
67	POLE	Does a weatherhead mast need to be guyed?	Mast guying is an NEC (customer) requirement that started in 1975. All masts must be adequately supported or guyed to safely support the service cable. This should be reported as a condition in FPI only if the mast is being pulled loose or is bent or leaning.	NEC (Not GO95 nor NESC)	

Imminent Threat Conditions

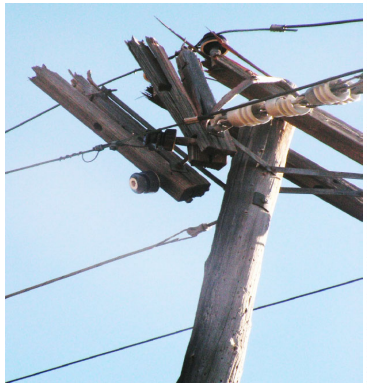
Imminent threat conditions are conditions found during a normal preventative maintenance inspection where it is deemed too dangerous for the inspector to leave. These conditions pose a present risk to safety or reliability

If these types of conditions are found, inspectors should contact dispatch immediately, secure the site and stay until crews arrive for further assessment and repair.

Imminent threat conditions should be entered into FPI with an "I" priority code and corrected when made safe

Examples of imminent threat conditions include, but are not limited to:
-Broken poles
-Broken cross arms
-Loose conductor (floaters)
-Public exposure to uncovered OH or UG energized equipment or apparatus
-Active smoking, sparking, or burning
-Extreme exposure to physical damage or system reliability
-Any condition that could reasonably be expected to present an extreme risk to people or property

Example Photos:



Procedure 069 : Condition Codes

Note: C-conditions are for CA supply only.

NO	CONDITION_CODE	COMPANY	STATE	DIST_TRANS	OH_UG	CONDITION_GROUP	DESCRIPTION_DETAILED
1	ABNDEQPM	PP	OR, CA	BOTH	OH	HARDWARE	PERMANENTLY IDLE/ ABANDONED EQUIPMENT/CONDUCTOR
2	ALUMBELL	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	ALUMINUM BELL END INSULATOR
3	AMIEQ	PP/RMP	ALL	BOTH	OH	OTHER	AMI RELATED CONDITION
4	ANCHIDLE	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	IDLE ANCHOR
5	ANCPUCO	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	PULLED/CORRODED ANCHOR
6	ANGELCUT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	ANGEL WING CUTOUT
7	ATSPLICE	PP/RMP	ALL	DISTRIBUTION	OH	HARDWARE	AUTOMATIC SPLICE INSTALLED IN SLACK SPAN OR REDUCED TENSION SPAN
8	AVIANDMG	PP/RMP	ALL	BOTH	OH	OTHER	AVIAN PROTECTION DEVICES DAMAGED
9	BIRDDMG	PP/RMP	ALL	BOTH	OH	BIRD RELATED	WOODPECKER HOLES
10	BIRDNST	PP/RMP	ALL	BOTH	OH	BIRD RELATED	BIRD NEST, LARGE IN PRIMARY
11	BIRDWST	PP/RMP	ALL	BOTH	OH	BIRD RELATED	CONTAMINATION/BIRD DROPPINGS
12	CANTINSP	PP/RMP	ALL	BOTH	OHUG	INSPECTION ISSUE	CANT INSPECT DUE TO CUSTOMER OBSTRUCTION
13	CAPDMGLS	PP/RMP	ALL	BOTH	OH	CAPACITOR	EQUIP DAMAGED/LOOSE
14	CFIBMID	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT MID-SPAN
15	CFIBMST	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO POWER SUPPLY AT MAST
16	CFIBPED	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	COMMUNICATION PEDESTRIAN CLEARANCE
17	CFIBPOLE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT POLE
18	CFIBRD	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE OF MESSENGER TO DRIVABLE SURFACE
19	CFIBRR	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE OF MESSENGER TO RAILROAD
20	CFIBSVC	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE CROSSING SERVICE
21	CHNCECUT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	ABB CHANCE CUTOUT
22	CLEAR	PP/RMP	ALL	BOTH	OH	CLEARANCE	THIS IS A CONDITION THAT WAS REASSIGNED TO CLEAR FOR POWER RESPONSIBILITY TO CORRECT
23	CLMBHAZ	PP/RMP	ALL	BOTH	OH	CLIMBING SPACE	CLIMBING SPACE ISSUE
24	CLMBTRE	PP	CA, OR, WA	BOTH	OH	VEGETATION	VEGETATION IN CLIMBING SPACE
25	CLRBLDG	PP/RMP	ALL	BOTH	OH	CLEARANCE	PRIMARY CONDUCTOR TO BUILDING / SIGN
26	CLRLOW	PP/RMP	ALL	BOTH	OH	CLEARANCE	LOW PRIMARY CONDUCTOR
27	CLRTOPOL	PP/RMP	ALL	BOTH	OH	CLEARANCE	UNATTACHED CONDUCTOR CLR TO POLE
28	CLRTOUCH	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE/PRIMARY NEUTRAL TOUCHING GUY/TRANSFORMER/POLE
29	COANT	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CELL ANTENNA OR WIFI ANTENNA
30	COANTRIS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBABLE RISER
31	COCATV	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	ANY CATV RELATED CONDITION THAT CAN NOT BE CATEGORIZED IN OTHER CATV CONDITION CODES
32	COFIBBND	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	COMM MESSENGER NOT BONDED/GROUNDED
33	COFIBBRG	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	BROKEN GUY OR PULLED ANCHOR
34	COFIBCLM	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBING SPACE CONDITION
35	COFIBER	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	ANY FIBER RELATED CONDITION THAT CAN NOT BE CATEGORIZED IN OTHER FIBER CONDITION CODES
36	COFIBEYE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SISTER OR AUXILIARY EYE
37	COFIBGUY	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SLACK GUY OR LONG TAIL
38	COFIBINS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	NO GUY INSULATOR OR NOT EFFECTIVELY GROUNDED
39	COFIBRIS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBABLE RISER
40	COFIBTRN	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	INCOMPLETE CHANGEOVER/TRANSFER
41	COMKLITE	PP/RMP	ALL	BOTH	OH	OTHER	AIRPORT OR AERIAL MARKER BALL MISSING OR LIGHT FAILED
42	CONDCOIL	PP/RMP	ALL	BOTH	OH	CONDUCTOR	COILED SERVICE WIRE HANGING FROM POLE
43	CONDFRAY	PP/RMP	ALL	BOTH	OH	CONDUCTOR	DAMAGED/FRAYED PRIMARY CONDUCTOR

44	CONDLOOS	PP/RMP	ALL	BOTH	OH	CONDUCTOR	BROKEN LOOSE TIE WIRE OR FLOATING CONDUCTOR
45	COOTHER	PP/RMP	ALL	BOTH	OHUG	OTHER	CONDITION OTHER
46	COPLLEAN	PP/RMP	ALL	BOTH	OH	POLE OTHER	POLE LEANING, NEEDS EVALUATION
47	CORRING	PP/RMP	ALL	BOTH	OH	INSULATOR	MISSING, DAMAGED OR LOOSE CORONA RING
48	COTELBND	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	COMM MESSENGER NOT BONDED/GROUNDED
49	COTELBRG	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	BROKEN GUY OR PULLED ANCHOR
50	COTELCLM	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBING SPACE CONDITION
51	COTELCO	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	ANY TELCO RELATED CONDITION THAT CAN NOT BE CATEGORIZED IN OTHER TELCO CONDITION CODES
52	COTELEYE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SISTER OR AUXILIARY EYE
53	COTELGUY	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SLACK GUY OR LONG TAIL
54	COTELINS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	NO GUY INSULATOR OR NOT EFFECTIVELY GROUNDED
55	COTELRIS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBABLE RISER
56	COTELTRN	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	INCOMPLETE CHANGEOVER/TRANSFER
57	COTVBND	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	COMM MESSENGER NOT BONDED/GROUNDED
58	COTVBRG	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	BROKEN GUY OR PULLED ANCHOR
59	COTVCLM	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBING SPACE CONDITION
60	COTVEYE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SISTER OR AUXILIARY EYE
61	COTVGUY	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	SLACK GUY OR LONG TAIL
62	COTVINS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	NO GUY INSULATOR OR NOT EFFECTIVELY GROUNDED
63	COTVRIS	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLIMBABLE RISER
64	COTVTRN	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	INCOMPLETE CHANGEOVER/TRANSFER
65	COVCFRAY	PP/RMP	ALL	BOTH	OH	CONDUCTOR	COVERED CONDUCTOR CONDITION FRAYED
66	COVCLOOS	PP/RMP	ALL	BOTH	OH	CONDUCTOR	COVERED CONDUCTOR CONDITION LOOSE
67	COVCOTHR	PP/RMP	ALL	BOTH	OH	CONDUCTOR	COVERED CONDUCTOR CONDITION OTHER CONDITION
68	CPSPLICE	PP/RMP	ALL	DISTRIBUTION	OH	HARDWARE	COMPRESSION SPLICE WITH INCORRECT NUMBER OF CRIMPS
69	CTELMID	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT MID-SPAN
70	CTELMST	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO POWER SUPPLY AT MAST
71	CTELPED	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	COMMUNICATION PEDESTRIAN CLEARANCE
72	CTELPOLE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT POLE
73	CTELRD	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE OF MESSENGER TO DRIVABLE SURFACE
74	CTELRR	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE OF MESSENGER TO RAILROAD
75	CTELSVC	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE CROSSING SERVICE
76	CTVMID	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT MID-SPAN
77	CTVMST	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO POWER SUPPLY AT MAST
78	CTVPED	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	COMMUNICATION PEDESTRIAN CLEARANCE
79	CTVPOLE	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE TO SUPPLY AT POLE
80	CTVRD	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE OF MESSENGER TO DRIVABLE SURFACE
81	CTVRR	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	CLEARANCE OF MESSENGER TO RAILROAD
82	CTVSVC	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (CLEARANCE)	CLEARANCE CROSSING SERVICE
83	CUSTACCE	PP/RMP	ALL	BOTH	OHUG	CUSTOMER RESPONSIBILITY	NO ACCESS/ACCESS DENIED/LOCKED GATE/CUSTOMER VEG. ISSUE
84	CUSTRESP	PP/RMP	ALL	BOTH	OHUG	CUSTOMER RESPONSIBILITY	CUSTOMER RESPONSIBILITY
85	CUSTWIRE	PP/RMP	ALL	BOTH	OH	MARKING/SIGNAGE	LIGHT, WIRE, ANTENNA, OR OTHER CUSTOMER ITEM ATTACHED TO POLE
86	CUTOUTAR	PP/RMP	ALL	BOTH	OH	CUTOUT OR ARRESTOR	CUTOUT/ARRESTOR ISSUE
87	DISTCLOW	RMP	UT, WY, ID	DISTRIBUTION	OH	CLEARANCE	LOW SAG PRIMARY OR OPEN SECONDARY
88	DISTHDWR	PP/RMP	ALL	DISTRIBUTION	OH	HARDWARE	MISSING OR LOOSE HARDWARE OR CONNECTION
89	DURABCUT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	DURABUTE CUTOUT
90	EARMSPCR	PP/RMP	ALL	BOTH	OH	CROSS ARM	EQUIPMENT ARM IS SPLIT/ CRACKED/ ROTTEN/ TWISTED/ TRACKING

91	ENCHCUG	RMP	UT, WY, ID	BOTH	UG	UNDERGROUND	UG CONFLICT
92	ENCHCUST	RMP	UT, WY, ID	BOTH	OH	ENTRANCE OR R.O.W ENCROACHMENT	CUSTOMER ITEM WITHIN MINIMUM APPROACH DISTANCE
93	ENCHRW	PP/RMP	ALL	BOTH	OH	ENTRANCE OR R.O.W ENCROACHMENT	LIGHT, WIRE, ANTENNA, OR OTHER CUSTOMER ITEM ATTACHED TO POLE
94	ENCHSVCE	PP/RMP	ALL	BOTH	OH	ENTRANCE OR R.O.W ENCROACHMENT	CUSTOMER ITEM LESS THAN 3" AT SERVICE ENTRANCE
95	EQUIPOIL	PP/RMP	ALL	BOTH	OHUG	EQUIPMENT LEAKING OIL	EQUIPMENT LEAKING OIL
96	EQUIPPAD	PP/RMP	ALL	BOTH	UG	UNDERGROUND	DAMAGED CONCRETE OR FIBERGLASS PAD / VAULT
97	EXSECOND	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	EXPOSED SECONDARY CONDUCTOR
98	EXSECONN	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	EXPOSED SECONDARY CONNECTION
99	FIREHYDR	PP/RMP	ALL	BOTH	OH	CUSTOMER RESPONSIBILITY	FIRE HYDRANT TOO CLOSE TO POLE
100	FOOTING	PP/RMP	ALL	BOTH	OH	TRANSMISSION	NEEDS TREATMENT OR CAP, IS BELOW GRADE, SEVERELY CRACKED/CRUMBLING
101	FOPOLERP	PP/RMP	ALL	BOTH	OH	OTHER	FOUND REJECT TAGS ON FOREIGN OWNED POLE
102	FRGNELEC	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	THIS IS FOR INTERNAL COMPANY USE AND FOR IDENTIFYING A FOREIGN ELECTRIC ATTACHMENT
103	GO95BLTC	PP	CA	BOTH	OH	HARDWARE	MISSING BOLT COVERS
104	GO95CL10	PP	CA	BOTH	OH	CLEARANCE	10 INCH CLEARANCE FROM EQUIPMENT TO SEC, NEUT OR SERVICE
105	GO95CLMF	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	FIBER CLIMBING SPACE CONDITION
106	GO95CLMP	PP	CA	BOTH	OH	CLIMBING SPACE	CLIMBING SPACE HAZARD
107	GO95CLMT	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	TELEPHONE CLIMBING SPACE CONDITION
108	GO95CLMV	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	CABLE TV CLIMBING SPACE CONDITION
109	GO95CLSV	PP	CA	BOTH	OH	CLEARANCE	SERVICE TOO LOW OVER GROUND
110	GO95CN	PP	CA	BOTH	OH	MARKING/SIGNAGE	COMMON NEUTRAL SIGN MISSING
111	GO95GUYB	PP	CA	BOTH	OH	ANCHOR OR GUY	BROKEN GUY
112	GO95GUYP	PP	CA	BOTH	OH	ANCHOR OR GUY	GUY OR INSULATOR IN BARREL OF PROXIMITY
113	GO95HV	PP	CA	BOTH	OH	MARKING/SIGNAGE	HIGH VOLTAGE SIGN MISSING
114	GO95MLD	PP	CA	BOTH	OH	GROUND OR MOLDING	MOLDING BROKEN, MISSING OR LOOSE
115	GO95STUB	PP	CA	BOTH	OH	POLE STUB OR CHANGEOVER	POLE STUB - UNDER 8.5 FEET IN PED AREA
116	GO95SVC	PP	CA	BOTH	OH	CLEARANCE	SERVICE WITHIN 3' OF HOUSE UNATTACHED
117	GO95TCH	PP	CA	BOTH	OH	CLEARANCE	MUST MAINTAIN 3" BETWEEN SERVICE WIRE AND POLE OR CROSSARM
118	GOCATVNP	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	NOT PROPERLY ATTACHED TO POLE OR ABANDONED EQUIPMENT
119	GOFIBNP	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	NOT PROPERLY ATTACHED TO POLE OR ABANDONED EQUIPMENT
120	GOFIBUN	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	UNATTACHED TO POLE WITHIN 15 INCHES
121	GOTELCNP	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	NOT PROPERLY ATTACHED TO POLE OR ABANDONED EQUIPMENT
122	GOTELUN	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	UNATTACHED TO POLE WITHIN 15 INCHES
123	GOTVUN	PP	CA	BOTH	OH	COMMUNICATIONS (OTHER)	UNATTACHED TO POLE WITHIN 15 INCHES
124	GRASSCUT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	GRASSHOPPER/TRIP O LIINK CUTOUT
125	GRD230BK	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	TRANSMISSION 230KV AND UP. BROKEN/MISSING GROUND OR INSUFFICIENT NUMBER OF GROUNDS
126	GRDBROKE	PP/RMP	ALL	BOTH	OH	GROUND OR MOLDING	BROKEN OR MISSING GROUND DISTRIBUTION, AND TRANSMISSION < 230KV
127	GRDRODHI	PP/RMP	ALL	BOTH	OH	GROUND OR MOLDING	HIGH GROUND ROD
128	GRDSHDBK	PP/RMP	ALL	BOTH	OH	GROUND OR MOLDING	GROUND BROKEN AT SHIELD WIRE / FIBER OPTIC GROUND
129	GUYBRK	PP/RMP	OR, WA, UT, WY, ID	BOTH	OH	ANCHOR OR GUY	BROKEN/CORRODED GUY
130	GUYHINS	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	HIGH GUY INSULATOR
131	GUYINSBK	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	BROKEN GUY INSULATOR
132	GUYLOINS	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	LOW GUY INSULATOR
133	GUYMARK	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	MISSING/BROKEN GUY MARKER
134	GUYNOINS	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	NO GUY INSULATOR OR NOT EFFECTIVELY GROUNDED
135	GUYSLACK	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	SLACK GUY
136	GUYTAIL	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	GUY TAIL TOO LONG
137	HORIARR	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	HORIZONTALLY MOUNTED ARRESTOR
138	HOTCLAMP	PP/RMP	ALL	DISTRIBUTION	OH	HARDWARE	HOT CLAMP DIRECTLY CONNECTED TO PRIMARY CONDUCTOR

139	HOTCLPAM	PP/RMP	ALL	DISTRIBUTION	OH	HARDWARE	HOT CLAMP DIRECTLY CONNECTED TO ARMOR ROD
140	INSPISSU	PP/RMP	ALL	BOTH	OHUG	INSPECTION ISSUE	CANT INSPECT DUE TO NON-CUSTOMER OBSTRUCTION
141	INSULBRK	PP/RMP	ALL	BOTH	OH	INSULATOR	BROKEN/GUNSHOT INSULATOR
142	INSULDMG	PP/RMP	ALL	BOTH	OH	INSULATOR	DAMAGED/LOOSE OR MISSING HARDWARE - DISTRIBUTION OR DISCOLORATION OR OTHER DAMAGE
143	INSULDRT	PP/RMP	ALL	BOTH	OH	INSULATOR	INSULATOR CONTAMINATED OR DIRTY
144	INSULPLM	PP/RMP	ALL	BOTH	OH	INSULATOR	INSULATOR (NOT SUSPENSION) NEEDS REPOSITIONED
145	IRSPOTOH	PP/RMP	ALL	BOTH	OH	INFRARED HOTSPOT	DIST OR TRANS IR CONDITION
146	IRSPOTUG	PP/RMP	ALL	BOTH	UG	INFRARED HOTSPOT	DIST OR TRANS IR CONDITION
147	JUMPCONT	PP/RMP	ALL	BOTH	OH	CONDUCTOR	JUMPERS/CONDUCTOR CONTACT
148	LATANODE	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	ANODE CONNECTION ISSUE
149	LATBNTMB	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	BENT MEMBER
150	LATCOR	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	EXCESSIVE CORROSION
151	LATHWARE	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	MISSING / LOOSE BOLTS / HARDWARE
152	LATMISMB	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	MISSING MEMBERS
153	LIGHT	PP/RMP	ALL	BOTH	OH	HARDWARE	DAMAGED/LOOSE HARDWARE
154	LWCATV	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	ONE OR MORE LASHING WIRES ARE BROKEN OR LOOSE ON THE CABLE TELEVISION LINE
155	LWFIBER	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	ONE OR MORE LASHING WIRES ARE BROKEN OR LOOSE ON THE FIBER OPTIC LINE
156	LWPAPS	PP/RMP	ALL	DISTRIBUTION	OH	CONDUCTOR	ONE OR MORE LASHING WIRES ARE BROKEN OR LOOSE ON THE SECONDARY PAPS (PARLEY) CABLE
157	LWTELCO	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (ENERGY RELEASE RISK)	ONE OR MORE LASHING WIRES ARE BROKEN OR LOOSE ON THE TELEPHONE LINE
158	MANHOLE	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND VAULT	MANHOLE COVER ACCESS
159	NARWPROF	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	NARROW PROFILE FRAMING
160	OCAPFUSE	PP/RMP	ALL	DISTRIBUTION	OH	CAPACITOR	SINGLE/TWO PHASE FUSES OPEN
161	OPENSEC	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	OPEN WIRE SECONDARY
162	PADCRETE	PP/RMP	ALL	BOTH	UG	UNDERGROUND	DAMAGED FIBERCRETE PAD / SPALLING OR CRACKING
163	PADINSUL	PP/RMP	ALL	BOTH	UG	UNDERGROUND	CRACKED OR BROKEN INSULATOR IN SWITCHGEAR
164	PADREPOS	PP/RMP	ALL	BOTH	UG	UNDERGROUND	REPOSITION EQUIPMENT ON PAD AND/OR REPLACE EQUIPMENT OR NEEDS FILL
165	PHRAISE	PP/RMP	ALL	BOTH	OH	HARDWARE	MISSING HARDWARE / COVER ON PHASE RAISER
166	POLABR	PP/RMP	ALL	BOTH	OH	POLE OTHER	POLE THAT HAS BEEN MECHANICALLY DAMAGED (NOT SUFFICIENTLY TO BE REPLACED), GENERALLY
167	POLANCRD	PP/RMP	ALL	BOTH	OH	ANCHOR OR GUY	POLE/ANCHOR SET IN CURB / ROADWAY
168	POLEDERP	PP/RMP	ALL	BOTH	OH	POLE REPLACE	DECAY REJECT REPLACE
169	POLEDMRS	PP/RMP	ALL	BOTH	OH	POLE REPLACE	DAMAGE REJECT RESTORE
170	POLEREPL	PP/RMP	ALL	BOTH	OH	POLE REPLACE	DAMAGE REJECT REPLACE
171	POLEREST	PP/RMP	ALL	BOTH	OH	POLE REPLACE	DECAY REJECT RESTORE
172	POLESTEP	PP/RMP	ALL	BOTH	OH	POLE OTHER	POLE STEP LESS THAN 8 FT ABOVE GROUND
173	POLETOP	PP/RMP	ALL	BOTH	OH	POLE OTHER	ROTTED/SPLIT/FEATHERED POLE TOP OR EXTENSION W/EQUIP OR CROSSARM
174	POLISSUE	PP/RMP	ALL	BOTH	OH	POLE OTHER	TRACKING ON POLE
175	POLTOPSW	PP/RMP	ALL	BOTH	OH	POLE OTHER	DAMAGED OR SEVERELY CORRODED CONNECTION
176	POLVIS	PP/RMP	ALL	BOTH	OH	OTHER	THIS IS A STRUCTURE THAT IS LESS THAN 4 FEET OF THE CURB OR ROAD EDGE AND DOES NOT HAVE ANY
177	PRIMVINE	PP/RMP	ALL	DISTRIBUTION	OH	VEGETATION	VINES CONTACTING PRIMARY CONDUCTOR/XFMR
178	PRITERM	RMP	UT, WY, ID	DISTRIBUTION	OH	GROUND OR MOLDING	DAMAGED TERMINATION ON UNDERGROUND RISER OR DIP POLES
179	PWRTRN	PP/RMP	ALL	BOTH	OH	POLE STUB OR CHANGEOVER	POWER INCOMPLETE CHANGEOVER/TRANSFER
180	RECLDMGL	PP/RMP	ALL	BOTH	OH	RECLOSER	EQUIP DAMAGED/LOOSE
181	REGDMGL	PP/RMP	ALL	BOTH	OH	HARDWARE	EQUIP DAMAGED/LOOSE
182	RISEBKSP	PP/RMP	ALL	BOTH	OH	RISER	BROKEN CONDUIT/JOINT SEPARATED OR IDLE RISER
183	RISECLMB	PP/RMP	ALL	BOTH	OH	RISER	CLIMBABLE
184	RISEGRD	PP/RMP	ALL	BOTH	OH	RISER	MISSING GROUNDING STRAP
185	RISEHDWR	PP/RMP	ALL	BOTH	OH	RISER	LOOSE OR MISSING HARDWARE ON RISER BRACKETS
186	RISESTRP	PP/RMP	ALL	BOTH	OH	RISER	MISSING/BROKEN CONDUIT STRAPS

187	SECENC	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	BROKEN BOX/PEDESTAL
188	SECFRAY	PP/RMP	ALL	DISTRIBUTION	OH	CONDUCTOR	DAMAGED/FRAYED SECONDARY CONDUCTOR
189	SECPAPS	RMP	UT, WY, ID	BOTH	OH	CONDUCTOR	WHITE-GRAY PAPS SECONDARY CABLE
190	SECVINE	PP/RMP	ALL	DISTRIBUTION	OH	VEGETATION	VINES CONTACITING SECONDARY CONDUCTOR
191	SPLICE	RMP	UT, WY, ID	BOTH	OH	CONDUCTOR	SPLICE ON OH CONDUCTOR
192	STUBCUST	PP	OR	BOTH	OH	POLE STUB OR CHANGEOVER	BARE POLE - CUSTOMER USE - BILL OF SALE
193	STUBO2	PP/RMP	OR, WA, UT, WY, ID	BOTH	OH	POLE STUB OR CHANGEOVER	BARE POLE REMOVE STUB, OVER 2 FT TALL
194	STUBU2	PP/RMP	OR, WA, UT, WY, ID	BOTH	OH	POLE STUB OR CHANGEOVER	BARE POLE REMOVE STUB, UNDER 2 FT TALL
195	SUPPLYCO	PP/RMP	ALL	BOTH	OH	OTHER	THIS IS A CONDITION THAT IS REASSIGNED TO POWER RESPONSIBILITY THAT IS NOT RELATED TO A COMMUNICATIONS CONDITION
196	SVCCOMMD	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE OF SERVICE POLE-TO-WEATHERHEAD OVER COMMERCIAL DRIVEWAY
197	SVCCUSTW	PP	OR	DISTRIBUTION	OH	CLEARANCE	CLEARANCE OF SERVICE OVER YARD CUSTOMER WIRE
198	SVCDECK	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE OF SERVICE TO DECK
199	SVCDEFLC	PP	OR, CA	BOTH	OH	VEGETATION	SERVICE WIRE DEFLECTED BY VEGETATION
200	SVCDRIVE	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE OF SERVICE OVER DRIVEWAY
201	SVCENTBK	PP/RMP	ALL	BOTH	OH	ENTRANCE OR R.O.W ENCROACHMENT	HOUSE KNOB PULLED OUT, OR BROKEN SERVICE GRIP OR ATTACHMENT
202	SVCENTCO	PP/RMP	ALL	BOTH	OH	ENTRANCE OR R.O.W ENCROACHMENT	BARE CONNECTORS AT WEATHER HEAD
203	SVCGUARD	PP	OR	DISTRIBUTION	OH	CLEARANCE	CLEARANCE OF SVC OVER YARD GUARD
204	SVCNEUT	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE TOUCHING NEUTRAL
205	SVCPOA	PP	OR	DISTRIBUTION	OH	CLEARANCE	CLEARANCE OF SERVICE OVER YARD POINT OF ATTACHMENT
206	SVCPOACU	PP	OR	DISTRIBUTION	OH	CLEARANCE	CLEARANCE OF SERVICE OVER YARD CUSTOMER POINT OF ATTACHMENT
207	SVCPOAGU	PP	OR	DISTRIBUTION	OH	CLEARANCE	CLEARANCE OF SERVICE OVER YARD POINT OF ATTACHMENT AND GUARD
208	SVCPOOL	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE CLEARANCE OVER POOL, HOT TUB
209	SVCROAD	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE OF SERVICE OVER ROADWAY
210	SVCROOF	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE TOO LOW OVER ROOF
211	SVCRR	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE TO RAILROAD (HORIZONTAL/VERTICAL)
212	SVCRUBCM	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE RUBBING COMM
213	SVCRUBLG	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE RUBBING HOUSE/ BUILDING
214	SVCSVC	PP/RMP	ALL	BOTH	OH	CLEARANCE	CLEARANCE TO ADJOINING SERVICE
215	SVCTREE	PP/RMP	ALL	BOTH	OH	POLE OTHER	SERVICE WIRE SUPPORTED BY A TREE (TREE POLE)
216	SVCWH	PP	OR	BOTH	OH	CLEARANCE	LOW WEATHERHEAD CLEARANCE
217	SVCWIND	PP/RMP	ALL	BOTH	OH	CLEARANCE	SERVICE TOO CLOSE TO WINDOW / SIGN
218	SVCYARD	PP/RMP	ALL	DISTRIBUTION	OH	CLEARANCE	CLR OF SVC OVER YARD
219	TRECATV	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	TREE LIMB DEFLECTING CATV LINE CAUSE STRAIN ON POLE OR SUPPLY LINE(S)
220	TREDIST	PP/RMP	ALL	DISTRIBUTION	OH	VEGETATION	DISTRIBUTION - TREE CONTACTING PRIMARY
221	TREECLMB	PP/RMP	ALL	BOTH	OH	VEGETATION	CLIMBABLE TREE TO PRIMARY
222	TREFIBER	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	TREE LIMB DEFLECTING FIBER LINE CAUSE STRAIN ON POLE OR SUPPLY LINE(S)
223	TRESCBRN	PP/RMP	ALL	BOTH	OH	VEGETATION	TREE CONTACTING OPEN (BARE CONDUCTOR) SECONDARY
224	TRESEC	PP/RMP	ALL	BOTH	OH	VEGETATION	TREE LIMB SEVERELY DEFLECTING SECONDARY SUPPLY (NON-BARE) LINE CAUSE STRAIN ON POLE OR
225	TRETELCO	PP/RMP	ALL	BOTH	OH	COMMUNICATIONS (OTHER)	TREE LIMB DEFLECTING TELCO LINE CAUSE STRAIN ON POLE OR SUPPLY LINE(S)
226	TRETRCLR	PP/RMP	ALL	TRANSMISSION	OH	VEGETATION	TRANSMISSION - TREE CLEARANCE
227	TRNCGRND	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	CLEARANCE TO GROUND
228	TRNCHOOK	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	DAMAGED/LOOSE C-HOOK OR PHASE FITTING
229	TRNCLOW	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	LOW SAG

230	TRNCON	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	CONSTRUCTION/BUILDING/LANDSCAPING/ BACKFILL
231	TRNCSAG	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	UNEVEN SAG
232	TRNSATT	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	LOOSE INSULATOR ATTACHMENT HARDWARE
233	TRNSBOND	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	HARDWARE NOT BONDED
234	TRNSBRAC	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	LOOSE X-BRACE ATTACHMENT HARDWARE
235	TRNSCENT	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	LOOSE/MISSING X-BRACE CENTER CLAMP/NUT
236	TRNSDAMP	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	DAMPER MISSING/DAMAGED/SLIPPED
237	TRNSGVLT	PP/RMP	OR, WA, UT, WY, ID	TRANSMISSION	OH	TRANSMISSION	TRANSMISSION TOWER HIGH VOLTAGE SIGN FADED/MISSING
238	TRNSKEY	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	MISSING/WEAK COTTER KEY
239	TRNSLOOS	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	HARDWARE LOOSE
240	TRNSNUTS	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	MISSING NUTS
241	TRNSOIL	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	SOIL MOVEMENT
242	TRNSPIN	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	PIN FALLING OUT
243	TRNSSIGN	PP/RMP	ALL	TRANSMISSION	OH	TRANSMISSION	MISSING TRANSMISSION LINE INTERSECTION AERIAL IDENTIFICATION SIGN
244	TRNVINE	PP/RMP	ALL	TRANSMISSION	OH	VEGETATION	VINES CONTACTING TRANSMISSION
245	UBBRACE	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	DISTRIBUTION CROSS ARM
246	UBPBANC	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	DISTRIBUTION ANCHOR ISSUE
247	UBPBCOND	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	DISTRIBUTION CONDUCTOR ISSUE
248	UBPBCTGD	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	BROKEN/CUT GROUND
249	UBPBCUAR	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	ARRESTOR/CUTOUT ISSUE
250	UBPBGYBK	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	BROKEN DISTRIBUTION GUY
251	UBPBGYSL	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	SLACK DISTRIBUTION GUY
252	UBPBTWFC	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	BROKEN TIE WIRE
253	UBPBXARM	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	CROSS ARM ON DISTRIBUTION ISSUE
254	UBPRMSHD	PP/RMP	ALL	DISTRIBUTION	OH	UNDERBUILD	MISSING HARDWARE
255	UBXARMIN	PP/RMP	ALL	BOTH	OH	UNDERBUILD	BROKEN INSULATOR
256	UGCOND	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG CONDUCTOR DAMAGED
257	UGEQBAR	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	MISSING LIVEFRONT BARRIERS
258	UGEQBKH	PP/RMP	ALL	BOTH	UG	UNDERGROUND	BROKEN LATCH/HINGES OR MISSING LOCK ON UG
259	UGEQBOLT	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	LIFTING BOLTS NOT REMOVED OR TURNED
260	UGEQFMNR	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	EXCESSIVE FOREIGN MATERIAL IN EQUIPMENT
261	UGEQRUST	PP/RMP	ALL	BOTH	OHUG	UNDERGROUND	OH OR UG TRANSFORMER SEVERELY RUSTED, DOOR OR TANK RUSTED ALLOWING ACCESS ON UG
262	UGEQTRCH	PP/RMP	ALL	BOTH	UG	UNDERGROUND	TRENCHING FROM PAD WAS NOT PROPERLY BACKFILLED
263	UGINSCVR	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG INSULATOR COVER MISSING/DAMAGED
264	UGINSDMG	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG INSULATOR DAMAGED
265	UGINSDRT	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG INSULATORS COMTAMINATED /DIRTY
266	UGPRIELB	PP/RMP	ALL	BOTH	UG	UNDERGROUND	PRIMARY UG ELBOW ISSUE
267	UGSHROUD	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG SUBMERABLE SHROUD DAMAGED/SLID
268	UGSPRING	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	FRACTURED/DAMGED POWER SPRING
269	UGTRACK	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG INSULATORS /TERMINATORS TRACKING
270	UGVLTBLT	PP/RMP	ALL	DISTRIBUTION	UG	UNDERGROUND	UG VAULT MISSING SECURING BOLTS/ACCSSABL
271	UNARRBLT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	UNCOVERED TANK MOUNTED ARRESTER BOLTS
272	UNCARRES	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	UNCOVERED ARRESTER
273	UNCBUSH	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	UNCOVERED PRIMARY BUSHING

274	UNCCUT	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	UNCOVERED CUTOUT
275	UNCINSUL	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	UNCOVERED INSULATOR
276	UNCJUMP	PP/RMP	ALL	DISTRIBUTION	OH	DOCUMENTATION	BARE JUMPERS
277	UNIGRDBM	PP/RMP	OR, WA, UT, WY, ID	BOTH	OH	GROUND OR MOLDING	BROKEN / MISSING MOLDING ON DELTA OR UNIGROUND SYSTEM
278	UNIGRDGR	PP/RMP	ALL	BOTH	OH	GROUND OR MOLDING	SEPARATION B/T GRD RODS LESS THAN 20 FT
279	UNIGRDSG	PP/RMP	ALL	BOTH	OH	GROUND OR MOLDING	SINGLE GROUND
280	VEGCANTI	PP/RMP	ALL	BOTH	OHUG	INSPECTION ISSUE	CANT INSPECT DUE TO VEGETATION
281	WASHOUT	PP/RMP	ALL	BOTH	OHUG	POLE OTHER	POLE WASHOUT - NEEDS BACKFILL
282	WRAPMESH	PP/RMP	ALL	BOTH	OH	POLE OTHER	MESH TYPE FIRE WRAPPED POLES
283	WRAPNMSH	PP/RMP	ALL	BOTH	OH	POLE OTHER	NON-MESH FIRE WRAPPED POLES
284	XARMBRAC	PP/RMP	ALL	BOTH	OH	CROSS ARM	CROSS BRACE BROKEN/MISSING/LOOSE
285	XARMSPCR	PP/RMP	ALL	BOTH	OH	CROSS ARM	ARM SPLIT/CRACKED/ROTTEN/TWISTED/TRACKING
286	XARMSQPN	PP/RMP	ALL	BOTH	OH	CROSS ARM	SQUATTER PIN
287	XFRGRNDG	PP/RMP	ALL	BOTH	OHUG	UNDERGROUND	BROKEN/MISSING GROUND OR INSUFFICIENT NUMBER OF GROUNDS.
288	XFRMBOBR	PP/RMP	ALL	BOTH	OH	TRANSFORMER	LOOSE BOLTS/ BRACKET OR MISSING BOLTS
289	XRFMBUIN	PP/RMP	ALL	BOTH	OH	TRANSFORMER	BROKEN BUSHING/INSULATOR

UPDATED: 12/20/2024

DESCRIPTION_DROP_DOWN	PRIORITY	DIFFERENTIATING	POLICY_REFERENCE	GO95	NESC
ABANDONED EQUIPMENT	C/D	Idle and abandoned conductors and equipment are a priority C in CA. D in OR. Pacific Power Only	N/A	GO95 Section 1-4, "Appendix I-Level 3"	N/A
ALUMINUM BELL END INSULATOR	D	For information only	N/A	GO95 Rule 18	NESC 234C3a
AMI RELATED CONDITION	B	AMI related condition which cannot be categorized in other condition codes. Physical damage to AMI equipment. RMP Only	N/A	GO95 Rule 94.4	NESC Rules 235I, 239G1 & 239H2
ANCHOR - IDLE ANCHOR	A/B	For RMP, "A" if ground rod is not flush with or below the ground level in high pedestrian traffic area. "B" if not in high pedestrian traffic area	N/A	GO95, Section I-2, Section I-3	NESC Rule 012C, NESC Rule 214B3
ANCHOR - PULLED/CORRODED	A/B	"A" if anchor is pulled or > 50% corrosion. "B" is < 50% corrosion present or other damage. Buried anchor is not a condition	Policy 009	GO95 Rule 61.3-A3b	NESC 261B
ANGEL WING CUTOUT	D	For information only	N/A	GO95 Rule 18	NESC Rule 012C
AUTOSPLICE INSTALLED/REDUCED TENSION SPN	B	"B" if automatic splice is installed in slack span or reduced tension span	N/A	GO95 Rule 44.1	N/A
AVIAN PROTECTION DEVICE DAMAGED	A/B/D	"A" if potential to affect system reliability. "B" if not immediate hazard. Priority "D" if not threat to reliability or safety	Policy 244	N/A	N/A
BIRDDMG - WOODPECKER HOLES	B	See policy references. Request a follow-up inspection (climbing or bucket truck) to determine extent of damage. OREGON: inspection performed no later than one year	Policy 045	GO95 Rule 31.1	NESC 012C
BIRDNST - NEST IN PRIMARY	B/D	"B" if likely to compromise reliability - notify area manager. "D" if deenergized and pose no threat to ignition hazard, fault risk or to the bird. For bird mortalities, contact	Policy 244; Bird Flowchart Combined Mortality and Nest	N/A	NESC 012C
BIRD WASTE-CONTAMINATION/DROPPINGS	B	B if likely to compromise reliability	N/A	GO95 Rule 44.1 (a)	NESC 012C
INSP ISSUE - CUSTOMER OBSTRUCTION	B	In comments note access issue. Construction obstruction, customer refusal, dog/animals, locked gate, honeybee box. See VEGCANTI and INSPISSU for	Policy 361, 298, 298 & 013	GO95 Rule 31.2	NESC Rule 312, NESC Rule 121A
CAPACITOR DAMAGED/LOOSE	B		Policy 009	GO95, Section I-3	NESC Rule 012C
CLEARANCE-FIBER AT MIDSPAN	B	Less than 100% of clearance is "B". Pole to pole midspan and/or service worker safety clearances are required	N/A	GO95 Rule 38 Table 2	NESC Rule 235C2b(1)(a) & 235C1, Exception 3
CLEARANCE-FIBER AT MAST	B	Less than 12" at mast.	N/A	GO95 Rule 54.8C4	NESC 235C1
COMMUNICATION PEDESTRIAN CLEARANCE	A/B	Less than 8' clearance is "A". Between 8' feet and required clearance is "B"	N/A	GO95 Rule 84.8(3)(a), 84.8(3)b & 84.8(3)(b)(Ex)	NESC Rule 232B1 (Table 232-1), 232B3 (Table 232-2)
CLEARANCE-FIBER AT POLE	B	If less than 100% of clearance, "B". Need worker safety zone and to street light.	N/A	GO95 Rule 92.1F(3)	NESC Rule 238-2, 238D & 235C1b
CLEARANCE-FIBER TO ROAD	A/B	Less than 14' clearance is "A". For pole-to-pole over residential driveways, less than 80% of the required clearance is "A". Less than 100% is a B	N/A	GO95 Rule 54.8, Table 1	NESC Rule 232B1, Table 232-1
CLEARANCE OF MESSENGER TO RAILROAD	A/B	Less than 22' clearance is "A". Between 22' feet and required clearance is "B"	N/A	GO95 Rule 37	NESC Rule 232B1 (Table 232-1)
CLEARANCE-FIBER XING SERVICE	B	If less than 100% of clearance, "B". Need 24" when off different support structure.	N/A	GO95 Rule 92.1F(3)	NESC Rule 233C1, Table 233-1
ABB CHANCE CUTOUT	D	For information only	N/A	GO95 Rule 18	NESC Rule 012C
CLEAR-POWER TO CORRECT COMM CLR	A/B		N/A	GO95 Rule 37, 38, Table 1 & 2	NESC Table 238-2, NESC Rule 238D, NESC Rule 235C1b
CLIMBING HAZARD	B	Supply issue in climbing space (long bolts, loose ground wire, vines/vegetation, etc.). In CA, climbing space hazards that are more than a supply space issue use condition	Policy 009	GO95 Rule 54.7	NESC Rule 217A4b, NESC 236A
VEGETATION IN CLIMBING SPACE	B	PP Only - Climbing Hazard Due To Vegetation In Climbing Space	N/A	GO95 Rule 54.7	NESC Rule 217A4b, NESC 236A
CLEARANCE: PRIMARY-BUILDING/SIGN	A		N/A	GO95 Rule 86.6 (f)	NESC Rule 234C1a, Table 234-1
CLEARANCE: PRIMARY LOW	A	Use GO95 clearances in CA; NESC clearances in all other states	N/A	GO95 54.5	NESC Rule 232B1, Table 232-1
UNATTACHED CONDUCTOR CLEARANCE TO POLE	B	less than 5 ft. to supply. Effectively grounded neutrals and service conductors of 300V or less can be 3 ft	N/A	GO95 Rule 54.4-D3, Table 1 Case 8	NESC Rule 234B1a, NESC Rule 234B2a
CLEARANCE TOUCHING GUY/XFMR/POLE	B		N/A	GO95 Table 2 case 9, Table 2 case 8	NESC Rule 235E, Table 235-6
ANTENNA CELL OR WIFI	B	Cell Antenna Or Wifi Antenna Related Conditions Which Cannot Be Categorized In Other Condition Codes	N/A	GO95 Rule 94.4	NESC Rule 235I, Table 235-6 row 1c, 239G1 & 239H2
COND-ANTENNA OR WIFI RISER CLIMBABLE	A/B	"A" if climbable into primary/neutral/open secondary. "B" if climbable into insulated secondary, or if supply riser is on same pole	N/A	GO95 Rule 94.8	NESC 217A
COND-CATV GENERAL	A/B/C	"C" condition only applies to California	N/A	GO95 Rule 18	N/A
COMM MESSENGER NOT BONDED/GROUNDED	B	Messengers shall be effectively grounded	N/A	GO95 Rule 92.4D & 93B	NESC Rule 215C1 & 215C5
COND-FIBER BROKEN GUY/PULLED ANCHOR	A		N/A	GO95 Rule 49.6	NESC Rule 264A, 214B2
COND-FIBER CLIMBING SPACE	B	Any condition resulting in no available climbing space. Thru-bolts are condition only if 4" beyond nut and in the only available climbing space	N/A	GO95 Rule 54.8	NESC Rule 217A4b, NESC 236A
COND-FIBER GENERAL	A/B/C	"C" condition only applies to California	N/A	GO95 Rule 18	N/A
COND-FIBER AUX/SISTER EYE	B	SISTER OR AUXILIARY EYE, married guy	N/A	GO95 Rule 86.7-B	N/A
COND-FIBER SLACK GUY-LONG TAIL	B		N/A	GO95 Rule 56.2	NESC Rule 264A, 214B2
COND-FIBER NO GUY INSUL/NOT GRNDED	B	No guy insulator or is not effectively grounded	N/A	GO95 Rule 49.5, 55.1, 57.7 (c)	NESC 215C2a & b
COND-FIBER RISER CLIMBABLE	A/B	"A" if climbable into primary/neutral/open secondary. "B" if climbable into insulated secondary, or if supply riser is on same pole	N/A	GO95 Rule 18	NESC 217A2
COND-FIBER INCOMPLETE TRANSFER	B	Comm has not transferred to new pole.	N/A	GO95 Rule 18	NESC RuleS 214A5, 214B3 & 234B
COND-MARKER BALL MSSNG/LIGHT FAILED	A/B	FAA required markers and lights. "A" if light failed. "B" if marker missing. Transmission and distribution	N/A	N/A	N/A
CONDUCTOR COILED AT POLE	A/B	A if energized and near comm lines/in public space. Otherwise "B"	Policy 009	GO95 Rule SEC 1-4, APPENDIX I-LEVEL 3	NESC Rule 214B2, NESC Rule 012C
CONDUCTOR DAMAGED/FRAYED	A/B	Dependent on degree of damage, > 50% of conductor strands cut = "A". If more than surface strands damaged. "B"	Policy 009	GO95, Section I-2, Section I-3	NESC 261H1

CONDUCTOR FLOATING/TIE WIRE BRK/LOOSE	A	If loose enough to free conductor, "A".	Policy 009	GO95, Section I-4	NESC Rule 214A5a, NESC Rule 012C
CONDITION OTHER	A/B/D	Used where no other condition code description defines issue. Inspector will need to document in detail issue.	N/A	N/A	N/A
CONDITION POLE LEANING	A/B	If leaning into roadway and an immediate hazard to vehicular traffic, "A". If leaning severely "A". If leaning moderately in urban area, "B".	N/A	GO95 Rule 18	NESC 261A2a
CORONA RING	A		N/A	GO95 Rule 18	NESC
COMM MESSENGER NOT BONDED/GROUNDED	B	Messengers shall be effectively grounded	N/A	GO95 Rule 92.4D & 93B	NESC Rule 215C1 & 215C5
COND-TELCO BROKEN GUY/PULLED ANCHOR	A		N/A	GO95 Rule 49.6	NESC Rule 264A, 214B2
COND-TELCO CLIMBING SPACE	B	Any condition resulting in no available climbing space. Thru-bolts are condition only if 4" beyond nut and in the only available climbing space.	N/A	GO95 Rule 54.8	NESC Rule 217A4b, NESC 236A
COND-TELCO GENERAL	A/B/C	"C" condition only applies to California	N/A	GO95 Rule 18	N/A
COND-TELCO AUX/SISTER EYE	B	SISTER OR AUXILIARY EYE, married guy	N/A	GO95 Rule 86.7-B	N/A
COND-TELCO SLACK GUY-LONG TAIL	B		N/A	GO95 Rule 56.2	NESC Rule 264A, 214B2
COND-TELCO NO GUY INSUL/NOT GRNDED	B	No guy insulator or is not effectively grounded	N/A	GO95 Rule 49.5, 55.1, 57.7 (c)	NESC 215C2a & b
COND-TELCO RISER CLIMBABLE	A/B	"A" if climbable into primary/neutral/open secondary. "B" if climbable into insulated secondary, or if supply riser is on same pole.	N/A	GO95 Rule 18	NESC 217A2
COND-TELCO INCOMPLETE TRANSFER	B	Comm has not transferred to new pole.	N/A	GO95 Rule 18	NESC RuleS 214A5, 214B3 & 234B
COMM MESSENGER NOT BONDED/GROUNDED	B	Messengers shall be effectively grounded	N/A	GO95 Rule 92.4D & 93B	NESC Rule 215C1 & 215C5
COND-CATV BROKEN GUY/PULLED ANCHOR	A		N/A	GO95 Rule 49.6	NESC Rule 264A, 214B2
COND-CATV CLIMBING SPACE	B	Any condition resulting in no available climbing space. Thru-bolts are condition only if 4" beyond nut and in the only available climbing space.	N/A	GO95 Rule 54.8	NESC Rule 217A4b, NESC 236A
COND-CATV AUX/SISTER EYE	B	SISTER OR AUXILIARY EYE, married guy	N/A	GO95 Rule 86.7-B	N/A
COND-CATV SLACK GUY-LONG TAIL	B		N/A	GO95 Rule 56.2	NESC Rule 264A, 214B2
COND-CATV NO GUY INSUL/NOT GRNDED	B	No guy insulator or is not effectively grounded	N/A	GO95 Rule 49.5, 55.1, 57.7 (c)	NESC 215C2a & b
COND-CATV RISER CLIMBABLE	A/B	"A" if climbable into primary/neutral/open secondary. "B" if climbable into insulated secondary, or if supply riser is on same pole.	N/A	GO95 Rule 18	NESC 217A2
COND-CATV INCOMPLETE TRANSFER	B	Comm has not transferred to new pole.	N/A	GO95 Rule 18	NESC Rule 214A5, 214B3 & 234B
COVERED CONDUCTOR CONDITION FRAYED	A/B	Dependent on degree of damage, > 50% of conductor strands cut = "A". If more than surface strands damaged, "B"	TBD	GO95 Rule 18	N/A
COVERED CONDUCTOR CONDITION LOOSE	A	If loose enough to free conductor, "A".	TBD	GO95 Rule 18	N/A
COVERED CONDUCTOR CONDITION OTHER COND	A/B	Another condition related to covered conductor, include in notes details.	TBD	GO95 Rule 18	N/A
COMPRESSION SPLICE W/INCORRECT # CRIMPS	B	"B" if compression splice does not have 6 crimps on each side of splice centerline	N/A	GO95 Rule 44.1	N/A
CLEARANCE-TELCO AT MIDSPAN	B	Less than 100% of clearance is "B". Pole to pole midspan and/or service worker safety clearances are required.	N/A	GO95 Rule 38 Table 2	NESC Rule 235C2b(1)(a) & 235C1, Exception 3
CLEARANCE-TELCO AT MAST	B	Less than 12" at mast.	N/A	GO95 Rule 54.8C4	NESC 235C1
COMMUNICATION PEDESTRIAN CLEARANCE	A/B	Less than 8' clearance is "A". Between 8' feet and required clearance is "B".	N/A	GO95 Rule 84.8(3)(a), 84.8(3)b & 84.8(3)(b)(Ex)	NESC Rule 232B1 (Table 232-1), 232B3 (Table 232-2)
CLEARANCE-TELCO AT POLE	B	If less than 100% of clearance, "B". Need worker safety zone and to street light.	N/A	GO95 Rule 92.1F(3)	NESC Rule 238-2, 238D & 235C1b
CLEARANCE-TELCO TO ROAD	A/B	Less than 14' clearance is "A". For pole-to-pole over residential driveways, less than 80% of the required clearance is "A". Less than 100% is a B.	N/A	GO95 Rule 54.8, Table 1	NESC Rule 232B1, Table 232-1
CLEARANCE OF MESSENGER TO RAILROAD	A/B	Less than 22' clearance is "A". Between 22' feet and required clearance is "B".	N/A	GO95 Rule 37	NESC Rule 232B1 (Table 232-1)
CLEARANCE-TELCO XING SERVICE	B	If less than 100% of clearance, "B". Need 24" when off different support structure.	N/A	GO95 Rule 92.1F(3)	NESC Rule 233C1, Table 233-1
CLEARANCE-CATV AT MIDSPAN	B	Less than 100% of clearance is "B". Pole to pole midspan and/or service worker safety clearances are required.	N/A	GO95 Rule 38 Table 2	NESC Rule 235C2b(1)(a) & 235C1, Exception 3
CLEARANCE-CATV AT MAST	B	Less than 12" at mast.	N/A	GO95 Rule 54.8C4	NESC 235C1
COMMUNICATION PEDESTRIAN CLEARANCE	A/B	Less than 8' clearance is "A". Between 8' feet and required clearance is "B".	N/A	GO95 Rule 84.8(3)(a), 84.8(3)b & 84.8(3)(b)(Ex)	NESC Rule 232B1 (Table 232-1), 232B3 (Table 232-2)
CLEARANCE-CATV AT POLE	B	If less than 100% of clearance, "B". Need worker safety zone and to street light.	N/A	GO95 Rule 92.1F(3)	NESC Rule 238-2, 238D & 235C1b
CLEARANCE-CATV TO ROAD	A/B	Less than 14' clearance is "A". For pole-to-pole over residential driveways, less than 80% of the required clearance is "A". Less than 100% is a B.	N/A	GO95 Rule 54.8, Table 1	NESC Rule 232B1, Table 232-1
CLEARANCE OF MESSENGER TO RAILROAD	A/B	Less than 22' clearance is "A". Between 22' feet and required clearance is "B".	N/A	GO95 Rule 37	NESC Rule 232B1 (Table 232-1)
CLEARANCE-CATV XING SERVICE	B	If less than 100% of clearance, "B". Need 24" when off different support structure.	N/A	GO95 Rule 92.1F(3)	NESC Rule 233C1, Table 233-1
CUSTOMER ACCESS/VEG ISSUE	B	Note problem in IF and record address.	N/A	GO95 Rule 31.2	NESC 213 and 214
CUSTOMER RESPONSIBILITY	A/B/D	Customer significant risk is "A". Customer low risk is "B".	N/A	GO95 Rule 34	N/A
CUSTOMER WIRE/LIGHT/OTHER ATTACH POLE	B	Antenna or other Customer items attached to pole >10' from supply space. See ENCHRW for items <10' from supply space.	N/A	GO95 Rule 34	NESC 217A-4
CUTOUT/ARRESTOR	A/B/D	Smoking, Sparking, tracking, Cracked porcelain, or split polymer is "A". "B" If Jumpered out or parts missing. Blown Arrester is "B". Priority D is RMP only for idle equip or	Policy 009	GO95, Section I-3	NESC Rule 012C
LOW SAG PRIMARY OR OPEN SECONDARY	D	Information only to support record keeping or other programs. Priority D is RMP only.	N/A	N/A	N/A
MISSING OR LOOSE HARDWARE OR CONNECTION	A/B	"A" if missing hardware. "B" if loose hardware. Expanded spring not a condition. Note hardware in comment field.	N/A	GO95 Rule 18 A-1	NESC Rule012C
DURABUTE CUTOUT	D	For information only	N/A	GO95 Rule 18	NESC Rule 012C
EQUIPMENT ARM ISSUE	A/B	Severe, "A". Moderate, "B". This code does not include: weather station equipment arms, guy arms, or crossarms.	N/A	GO95 Rule 49.2-C	NESC Rule 012C & 252

ENCROACHMENT R.O.W. UG CONFLICT	D	Indicate issue in comment field. Priority D is RMP only.	N/A	N/A	N/A
ENCROACHMENT R.O.W. CUST IN M.A.D.	B	RMP only: Customer item is attached at pole more than 10' from lowest power. For PP, use CUSTWIRE	N/A	N/A	N/A
ENCROACHMENT R.O.W. CUST ATTCH POLE	A/B	If within 40" of primary or open secondary conductor, "A". Between 40" and 10' is a "B". Otherwise it gets classified as (ENCHCUST-RMP) or (CUSTWIRE-PP). Public	N/A	GO95 Rule 34	NESC 217A4
CUSTOMER ITEM <3" AT SERVICE ENTRANCE	A/B	A priority if contacting, B if customer is less than 3" at service entrance	N/A	GO95 Rule 54.8	NESC 234C3c
EQUIPMENT LEAKING OIL	A / B	Actively leaking oil onto the ground or into the environment is "A". Weeping oil is a priority B (California Only). Note type of equipment leaking oil in comment field.	Policy 009	GO95, Section I-2	NESC Rule 214A5a, NESC Rule 012C
PAD/VAULT DAMAGED	A/B	Exposed with access is "A". Badly damaged w/o access is "B".	N/A	GO128 Rule 31.3, 33.5	NESC Rule 323 A&I, 363A
EXPOSED SECONDARY CONDUCTOR	D	For information only	N/A	GO95 Rule 18	NESC 012C
EXPOSED SECONDARY CONNECTION	D	For information only	N/A	GO95 Rule 18	NESC 234C3a
FIRE HYDRANT CLR TO POLE	B	Resolve with local fire dept.	N/A	N/A	NESC 231A
FOOTING, CONCRETE	B/D	RMP only: Priority B is RMP only, for severe deterioration/damage with exposed rebar needs treatment. Minor deterioration (erosion, cracking, spalling, flaking, chipping) of	N/A	GO95 Rule 18	NESC 261a/b
FOREIGN OWNED POLE REJECT	B	Report reject tags on foreign owned pole as B priority.	Policy 008	GO95 Rule 44.1, Table 4	NESC 261A2a
FOREIGN ELECTRIC ISSUE	A/B/D	Priority D is RMP only.	N/A	GO95 Rule 18	N/A
GO95 BOLT COVERS MISSING	C	Bolts supporting energized equipment are required to be covered. Pacific Power Only. California Only.	N/A	GO95 II-17	N/A
GO95 CLEARANCE CONDITION	B/C	"B" if wire is contacting transformer, capacitor or other similar apparatus. "C" if clearance is less than 10". Pacific Power Only. California Only.	N/A	GO95 Rule 54.9-E(2)C	N/A
GO95 CLIMBING SPACE - FIBER ISSUE	B	Pacific Power Only. California Only.	N/A	GO95, Section I-4	N/A
GO95 CLIMBING SPACE - POWER ISSUE	B	Record as a condition if climbing hazard cannot be easily remedied during ascent. Pacific Power Only. California Only.	N/A	GO95 I-4	NESC 236A
GO95 CLIMBING SPACE - TELCO ISSUE	B	Pacific Power Only. California Only.	N/A	GO95, Section I-4	N/A
GO95 CLIMBING SPACE - TV ISSUE	B	Pacific Power Only. California Only.	N/A	GO95, Section I-4	N/A
GO95 GROUND CLEARANCE CONDITION	A/B	"A" = less than 7'. "B" = from 7' to 8.49'. Pacific Power Only. California Only.	N/A	GO95 Rule 54.8-B3, Table 10	N/A
GO95 COMMON NEUTRAL SIGN MISSING	C	Neutral sign may be a >1" tag or sign with text >3".	N/A	GO95 Section V-165, Section V-166, "Rule 59.3-F"	N/A
GO95 GUY BROKEN	A/B/C	"A" if broken/damaged in barrel of proximity to HV, "B" if out of proximity. Pacific Power Only. California Only.	N/A	GO95, Section I-2, Section I-3	N/A
GO95 GUY/INSUL IN BARREL OF PROXIMITY	C	Guy and insulator must be more than one foot from primary. Insulator also must be a) more than 6' from pole and b) more than 8' below primary. Pacific Power Only.	N/A	GO95 Section V-125, "Rule 56.6-A"	N/A
GO95 HIGH VOLTAGE SIGN MISSING	C	HV sign missing, faded or cracked, exception for remote locations which are inaccessible by vehicle. Pacific Power Only. California Only.	N/A	GO95 Rule 51.6-A, Section V-17	N/A
GO95 MOLDING BROKEN/CRACKED/MISSING	B/C	"B" if in communications or public area, otherwise "C". Pacific Power Only. California Only.	N/A	GO95 I-3, I-4, J-5	N/A
GO95 POLE STUB ISSUE	A/B	"A" = hollowed out butt in pedestrian area. "B" = pedestrian area and less than 8.5' high. Pacific Power Only. California Only.	N/A	GO 95 Rule 84.8-C4b - PDF Page 374	N/A
GO95 SERVICE CLEARANCE ISSUE	B	3' horizontal clearance is required. No requirement if attached, In California Only. Pacific Power Only.	N/A	GO95 Rule 54.8B, Table 10	N/A
GO95-NEED 3" GAP SVC TO POLE/XARM	B	California supply service only. Pacific Power Only.	N/A	GO95 Table 2 case 9, Table 2 case 8	N/A
GO95 CATV IMPROPERLY ATTCH/ABANDN	C	Pacific Power Only. California Only.	N/A	GO 95 Rule 18	N/A
GO95 FIBER IMPROPERLY ATTCH/ABANDN	C	Pacific Power Only. California Only.	N/A	GO95 Rule 18	N/A
GO95 FIBER UNATTACHED W/IN 15"	B	See Table 1 Case B8 and Rule 84.4D. Need 15 inches to pole centerline. If supply is attached and comm pole is not within ten feet of supply pole, need 22.5 inches. Pacific	N/A	GO95 Table 1 Case B8, Rule 84.4D, Section VIII-47	N/A
GO95 TELCO IMPROPERLY ATTCH/ABANDN	C	Pacific Power Only. California Only.	N/A	GO95 Rule 18	N/A
GO95 TELCO UNATTACHED W/IN 15"	B	See Table 1 Case B8 and Rule 84.4D. Need 15 inches to pole centerline. If supply is attached and comm pole is not within ten feet of supply pole, need 22.5 inches. Pacific	N/A	GO95 Table 1 Case B8, Rule 84.4D, Section VIII-47	N/A
GO95 CATV UNATTACHED W/IN 15"	B	See Table 1 Case B8 and Rule 84.4D. Need 15 inches to pole centerline. If supply is attached and comm pole is not within ten feet of supply pole, need 22.5 inches. Pacific	N/A	GO95 Table 1 Case B8, Rule 84.4D, Section VIII-47	N/A
GRASSHOPPER/TRIP O LINK CUTOUT	D	For information only	N/A	GO95 Rule 18	NESC Rule 012C
GROUND BRK/MSNG 230KV AND HIGHER	A	If shield is present, pole must be grounded. If there's no shield and the metal parts are bonded together, no pole ground is required.	N/A	GO95 Rule 21.4 & Rule 18	NESC 092B2
GROUND BRK/MSNG LESS THAN 230KV	A/B	Equipment ground on delta is an "A". Any broken ground less than 8 ft above earth is "A" or can get blown into phase conductor is an "A". Another broken ground is "B". For	Policy 009	GO95 Rule 21.4	NESC 093D3, 215B
GROUND ROD HIGH	A/B	For PP, "B" if ground rod is not flush with or below the ground level. For RMP, "A" if ground rod is not flush with or below the ground level in high	Policy 009 Section 3.5	GO95 Rule 59.4A(2)	NESC 094B2a(3)
GROUND-BROKEN AT SHIELD WIRE/FIBER	A/B	If ground wire is long enough to get blown into a phase conductor, "A". Otherwise "B".	N/A	GO95 Rule 21.4 & Rule 18	NESC
GUY BROKEN/CORRODED	A/B	"A" if broken, "B" if corroded > 50%. (For CA see GO95GUYB.)	Policy 009	GO95 Rule 56.2	NESC 261C2
GUY INSULATOR HIGH	B	Insulator too high above power to protect public space	Policy 009	GO95 Rule 56.7C	NESC 215C2
BROKEN GUY INSULATOR	B	Guy insulator broken or damaged	Policy 009	GO95 Rule 49.5, 55.1, 57.7c	NESC Rule 279a
GUY INSULATOR LOW	B	Bottom of guy insulator less than 8 ft above ground when broken and no ground bond. Refer to Grandfather Matrix.	Policy 009	GO95 Rule 56.7C	NESC 215c4a
GUY MARKER MISSING/BROKEN	B/C	Fix at time of inspection (where contract allows). Marker not required if guy is not exposed to pedestrians or traffic and/or is engulfed in dense vegetation or is otherwise	Policy 009	GO95 56.9	NESC 217C
GUY NOT GROUNDED/NO INSULATOR	B	No guy insulator or is not effectively grounded	Policy 009	GO95 Rule 86.6, 56.7, 21.5-C &D	NESC 215C2a & b
GUY SLACK	A/B	"A" if visibly slack with potential to contact energized facilities or contacting other conductors. "B" if visibly slack in CA. For all other States, "B" if slack and pole is not in	Policy 009 Section 3.3(d)	GO95 Rule 56.2	NESC 261A5C & 264A
GUY TAIL TOO LONG	B	Fix this at the time of inspection (if contract allows), if you can't then use this condition code.	Policy 009 Section 3.3(f)	GO95 Rule 18	NESC
HORIZONTALLY MOUNTED ARRESTOR	D	For information only	N/A	GO95 Section I-3	NESC Rule 012C
HOT CLAMP DIRECTLY CONNECTED TO PRIMARY	B	"B" if hot line clamp is directly connected to mainline primary conductor instead of stirrup.	N/A	GO95 Rule 18	N/A

HOTCLAMP DIRECTLY CONNECTED TO ARMOR ROD	B	No differentiator as only a 'B' condition is allowed	N/A	GO95 Rule 18	NESC 012C
INSP ISSUE - NON-CUSTOMER OBSTRUCTION	B	In comments note access issue. No road, impassable, cliff, river, or other natural obstruction. See VEGCANTI and INSPISSU for vegetation and non-customer related	Policy 361,298, 298 & 013	GO95 Rule 31.2	NESC 121A, NESC 213, NESC 312
INSULATOR BROKEN/SHOT	A/B/D	If tracking, assign an "A". As per policy reference.	Policy 012	GO95 Rule 44.3	NESC 273
INSULATOR DAMAGE/LOOSE/MSSNG EQUIP	A/B/D	If damaged, per Insulator Policy 012.	Policy 012	N/A	NESC 261H2
INSULATOR DIRTY/CONTAMINATED	D	Information Only	Policy 012	N/A	N/A
INSULATOR NEEDS REPOSITIONING	A/B	"A" is insulator out of lead/alignment (twisting force on insulator) by more than 2". "B" is out of alignment <2" and >0". Not applicable to suspension insulators	N/A	GO95 Rule 18	NESC 277
DIST OR TRANS IR CONDITION	A/B	"A" for rise temperatures greater than or equal to 64°F. "B" for rise temperatures between 10°F and 63°F. Send images and report to Asset Management	Policy 358	N/A	N/A
DIST OR TRANS IR CONDITION	A/B	"A" Temperature difference (Delta-T greater than 15°C. "B" Temperature difference (Delta-T) between 5°C to 15°C	Procedure 346	N/A	N/A
JUMPERS/CONDUCTOR CONTACT	A	No differentiator as only a 'A' condition is allowed	N/A	GO95 Section I-3	NESC 012C
LATTICE STRC-ANODE CONNECTION	B		N/A	GO95 Rule 18	N/A
LATTICE STRC-BENT MEMBER	B		N/A	GO95 Rule 18	N/A
LATTICE STRC-EXCESSIVE CORROSION	B		N/A	GO95 Rule 18	N/A
LATTICE STRC-MISSING BOLTS/HDWARE	A/B	If jeopardizing structural integrity, "A".	N/A	GO95 Rule 18	N/A
LATTICE STRC-MISSING MEMBERS	A/B	If jeopardizing structural integrity, "A".	N/A	GO95 Rule 18	N/A
LIGHT - DAMAGED/LOOSE HARDWARE	A/B	"A" if light hanging from pole or if conduit access in public space, "B" if lens cover open	N/A	GO95 Rule 18	NESC Rule 012C
LASHING WIRE - CATV	A	Broken or loose lashing wire is always an "A" priority condition	N/A	GO95 Rule 18 APENENDIX 1 LEVEL 1	NESC Rule 012C
LASHING WIRE - FIBER	A	Broken or loose lashing wire is always an "A" priority condition	N/A	GO95 Rule 18 APENENDIX 1 LEVEL 1	NESC Rule 012C
BROKEN LASHING WIRE ON SEC PARLEY CABLE	A	Broken lashing wire is an "A" priority	N/A	GO95 Rule 18 APENENDIX 1 LEVEL 1	N/A
LASHING WIRE - TELCO	A	Broken or loose lashing wire is always an "A" priority condition	N/A	GO95 Rule 18 APENENDIX 1 LEVEL 1	NESC Rule 012C
MANHOLE COVER ACCESS	A/B	"A" assigned to condition reflecting an existing lack of structural integrity, such as potential access to the interior, exposed wires, missing or cracked lids, or inability to	N/A	GO128 Rule 32	NESC Rule 323
NARROW PROFILE FRAMING	D	For information only	N/A	GO95 Section I-3	NESC 012C
SINGLE/TWO PHASE FUSES OPEN	A	"A" if one or two phases have fuses open	N/A	GO95 Rule 58.1	NESC Rule 012C
OPEN WIRE SECONDARY	D	For information only	N/A	GO95 Rule 18	NESC Rule 261H1 & 012C
PAD-DAMAGED/SPALLING/CRACKING	A/B	Cracked/spalling Fibercrete around padmount equip or hole with exposed access is "A". Localized cracks/spalling or hole without access is "B"	N/A	GO128 Rule 32.3	NESC Rule 380C
PAD-INSULATOR IN SWITCHGEAR BROKEN	A	"A" is broken or cracked	Policy 008	GO128 Rule 34.3C	NESC Rule 012C, 312, 313A
PAD-REPOSITION/REPLACE EQUIPMENT	A/B	Exposed with access to wires/live equipment is "A", otherwise not a condition. If slid on pad but no access B	N/A	GO128 34.3	NESC Rule 321B, 381G
MISSING HARDWARE / COVER ON PHASE RAISER	A/B	"A" if loose or missing hardware. "B" if missing cover only	N/A	GO95 Rule 18	NESC Rule 214A 261A2
POLE-ABRADED BY VEHICLE	D	This is to be able to pull reports for information	N/A	GO95 Rule 18	NESC Rule 012C
POLE-ANCHOR SET IN CURB/ROADWAY	B		N/A	GO95 Rule 18	NESC 231B
POLE-DECAY/REJECT/REPLACE	A/B	As per relative policy reference.	Per Policy 013, or 298 (CA), or 299 (OR)	GO95 Rule 44.1, Table 4	NESC 261A2a
POLE-DAMAGE/REJECT/RESTORE	A/B	As per relative policy reference.	Per Policy 013, or 298 (CA), or 299 (OR)	GO95 Rule 44.1, Table 4	NESC 261A2a
POLE-DAMAGE/REJECT/REPLACE	A/B	As per relative policy reference.	Per Policy 013, or 298 (CA), or 299 (OR)	GO95 Rule 44.1, Table 4	NESC 261A2a
POLE-DECAY/REJECT/RESTORE	A/B	As per relative policy reference.	Per Policy 013, or 298 (CA), or 299 (OR)	GO95 Rule 44.1, Table 4	NESC Rule 012C
POLE-STEP <8 FEET ABOVE GROUND	B	Does not apply to isolated or otherwise inaccessible structures. Inspector corrects on the spot when possible	N/A	GO95 Rule 91.3-C	NESC 217A2b
ROTTED/SPLIT POLE TOP/EXT W/EQU OR XARM	A/B/D	If feathered top impacts ridge pin, cross arm or other supply issue then "A". "B" if severe but not creating issues as noted in "A" condition. "D" if condition is not severe	Per Policy 013, or 298 (CA), or 299 (OR)	GO95 Rule 18	NESC 261A2
TRACKING ON POLE	A/B	"A" If severe. "B" If moderate.	N/A	GO95 Rule 18	NESC 261A
DAMAGED OR SEVERELY CORRODED CONNECTION	A/B	If actively tracking "A". Non-operable or other issues "B".	N/A	GO95 Rule 18	NESC Rule 012C
POLE-VIS. STRIPE/BARRIER MISSING	D	This is to be able to pull reports for information	N/A	N/A	N/A
VINES CONTACTING PRIMARY CONDUCTOR/XFMR	A/B	"A" if contacting primary conductor or equipment. "B" if contacting primary covered conductor	N/A	GO95 Rule 34, 35	NESC Rule 217A4, NESC 218A
TERMINATION CONNECTION ISSUE	A	"A" if termination is damaged.	N/A	N/A	N/A
POWER INCOMPLETE CHANGEOVER/TRANSFER	B	"B" for all incomplete changeover issues.	N/A	GO95 Rule 18	NESC Rule 214B3
RECLOSER EQUIPMENT DAMAGED/LOOSE	B		Policy 009	GO95 Rule 18	NESC Rule 012C
REGULATOR EQUIPMENT DAMAGED LOOSE	B		Policy 009	GO95 Rule 18	NESC Rule 012C
RISER BRKN/SEPARATED CONDUIT/JOINT	A/B	"A" if below 8 ft. "B" if above 8 ft. Idle riser only "A" condition if conductor is accessible to the public	N/A	GO96 54.6-D2-5, 54.6-E	NESC RULE 362A
RISER CLIMBABLE	A/B	"A" if climbable into primary/neutral/open secondary.	N/A	GO95 Rule 18	NESC 217A2
RISER GROUND STRAP MISSING (STEEL)	B	Newer installs have grounding sticker.	N/A	GO95 Rule 54.6E(1)	NESC Rule 314B
RISER MISSING/LOOSE HARDWARE	A/B	"A" if hardware is missing and riser is not secure." B" if harware is loose but riser is secure	NA	GO95 Rule 54.6	NESC 361B
RISER MISSING/BRK CONDUIT STRAPS	A/B	Primary conduit not secured to pole = "A". Secondary conduit not secured to pole = "B"	N/A	GO95 Rule 54.6E(1)	NESC Rule 361B

SECONDARY ENCL BROKEN BOX/PEDESTAL	A/B	"A" assigned to condition reflecting an existing lack of structural integrity, such as potential access to the interior, exposed wires, missing or cracked lids, or inability to	N/A	GO128 Rule 34.3-C	NESC Rule 323D, 381G1
SECONDARY ISSUE	A/B	Dependent on degree of damage, > 50% of conductor strands cut = "A". If more than surface strands damaged, "B"	N/A	GO95 Rule 18	NESC Rule 261H1 & 012C
SECONDARY CABLE WHITE-GRAY PAPS	D	For information only. RMP Only.	N/A	N/A	N/A
VINES CONTACITING SECONDARY CONDUCTOR	A/B	"A" if contacting open secondary, "B" if contacting insulated (sec bare) secondary	N/A	GO95 Rule 34, 35	NESC Rule 217A4, NESC 218A
SPLICE ON OH CONDUCTOR	D	Information only to support record keeping or other programs. RMP Only	N/A	N/A	N/A
STUB-CUST USE-BILL OF SALE	B/D	For Oregon only. PP Only.	N/A	N/A	NESC Rule 214B3
STUB-REMOVE-OVER 2 FEET TALL	B	For CA see GO95STUB	N/A	N/A	NESC 214B3
STUB-REMOVE-UNDER 2 FEET TALL	A/B	"A" = publicly accessible, cut off AND hollowed out. "B" = cut off at or below ground level. For CA see GO95STUB	N/A	N/A	NESC Rule 214B3
SUPPLYCO-POWER CONDITION NOT COMM	A/B		N/A	GO95 Rule 18	N/A
SVC CLR TO WHD OVER CMRCL DVWY	A/B	See Clearance Table Less than 80% is "A"	N/A	GO95 Rule 54.8B(2)(a)	NESC Table 232-2
CLR OF SVC OVER YARD CUSTOMER WIRE	A/B	Can be guarded with customer involvement. Less than 8 feet of clearance is "A". Between 8 feet and required clearance is "B".	Policy No 336	N/A	N/A
SVC CLEARANCE OVER DECK	A/B	If service or weatherhead is reachable horizontally less than 2 feet is "A", between 2 to 5 feet is "B". Vertical clearance: less than 8 feet from surface of deck is "A", from 8	N/A	GO95 Rule 84.8-C4(b)	NESC Rule 234C3d(3), NESC Rule 234C3d(1)
SVC DEFLECTED BY VEGETATION	B	Only Oregon or California when deflecting. This is not a condition if already guarded at the point of deflection	OAR 860-024-016(6)	GO95 Rule 35	N/A
SVC DRIVEWAY CLEARANCE CONDITION	A/B	Less than 8 feet of clearance is "A". From 8 feet to required clearance is "B"	See "CLEARANCE" and "GRANDFATHERING MATRIX"	GO95 Rule 54.8B(2)(b)	NESC Rule 232B1, Table 232-1
SVC ENTRANCE-BRKN GRIP/ATTACHMENT	A/B	"A" if conductor connectors are under tension. Otherwise "B".	N/A	GO95 Rule 18	NESC Rule 234C3c
SVC ENT BARE CONNECTOR AT WHD	A/B	If readily accessible, "A". If accessible from roof, window, etc, "B".	Standards ET312 and DE531	GO95 Rule 18	NESC Rule 234C3a
CLEARANCE OF SVC OVER YARD GUARD	A/B	OREGON ONLY: Guarding PacifiCorp wire will correct condition. Less than 8 feet of clearance is "A"	Policy 336	N/A	NESC Rule 232B1, Table 232-1
SVC TOUCHING NEUTRAL	B		N/A	GO95 Rule 54.4	NESC Rule 235E, Table 235-6
CLR OF SVC OVER YARD POA	A/B	Can be raised to 10 feet without customer involvement. Less than 8 feet of clearance is "A"	Policy 336	N/A	NESC Rule 232B1, Table 232-1
CLR OF SVC OVER YARD CUSTOMER POA	A/B	Can be raised to 10 feet with customer involvement. Less than 8 feet of clearance is "A"	Policy 336	N/A	NESC Rule 232B1, Table 232-1
CLR OF SVC OVER YARD POA & GUARD	A/B	OREGON ONLY: Can be corrected by both raising to 10 feet without customer involvement and guarding. Less than 8 feet of clearance is "A". Between 8 feet and	Policy 336	N/A	NESC Rule 232B1, Table 232-1
SVC POOL/HOT TUB CLEARANCE	A	GO95 clearances in California. NESC in other states. This is for permanently installed above or in ground pool or hot tub	N/A	GO95 Rule 54.4-A3	NESC Rule 234E, Table 234-3
CLR OF SVC OVER ROADWAY	A/B/D	See Clearance Table. Less than 80% is "A". From 80% to 99.9% is "B". Road xing direct to point of service November thru February, 16' 17' is "D"	N/A	GO95 Rule 54.8B(1)	NESC Rule 232B1, Table 232-1
SVC ROOF CLEARANCE	B	See grandfathering matrix, if it does not meet the requirements it's a B	N/A	GO95 Rule 54.8-B4a	NESC Rule 234C3d(1)b
CLEARANCE TO RAILROAD (HORIZ/VERTICAL)	A/B	Refer to PacifiCorp's Inspection Clearance Table	N/A	GO95 Rule 54.8, Table 1	NESC Rule 232B1, Table 232-1
SVC RUBBING COMMUNICATION WIRE	A		N/A	GO95 Rule 54.4	NESC Rule 235C1, Exception 3
SVC RUBBING HOUSE/BUILDING	B		N/A	GO95 Rule 54.4-H	NESC Rule 234C3c
CLEARANCE TO ADJOINING SERVICE	B	Service rubbing on another service.	N/A	GO95 Rule 54.10C(6)	NESC Rule 233C1, Table 233-1
SERVICE WIRE SUPPORTED BY A TREE	D	No differentiator as only a 'D' condition is allowed	N/A	GO95 Rule 35	NESC 217B
LOW WEATHERHEAD CLEARANCE	A/B	OREGON ONLY-A priority if weatherhead below 8', B priority if weatherhead between 8' and 10'	Policy 336	N/A	NESC Rule 232B1, Table 232-1
SVC WINDOW CLEARANCE	B		N/A	GO95 54.8B4	NESC Rule 234C2, Table 234-1
CLR OF SVC OVER YARD	A/B	Less than 8 feet of clearance is "A". Between 8 feet and required clearance is "B"	Policy 336	N/A	NESC Rule 232B1, Table 232-1
TREE DEFLECT TV LINE	B		N/A	GO95 Rule 35	N/A
DISTRIBUTION - TREE CONTACTING PRIMARY	A	"A" if tree contacting primary. Tree contacting neutral is not a condition.	N/A	GO95 Rule 35	NESC Rule 218A1
TREE CLIMBABLE	A		860-024-0016	GO95 Rule 35	NESC Rule 217A2a & 214A5
TREE DEFLECT FIBER LINE	B		N/A	GO95 Rule 35	N/A
TREE CONTACTING OPEN SECONDARY	A	"A" if tree contacting secondary bare conductor in fire risk areas. Otherwise "A" if contacting bare conductor with severe deflection	860-024-0016	GO95 Rule 35	NESC Rule 218A1 & 218A2
SVC/SEC SEVERELY DEFLECT/ABRADED BY VEG	A	Tree Limb Severely Deflecting Secondary Supply (Non-Bare) Line Cause Strain On Pole or Abrasion Of Secondary/Service Supply Line(S)	N/A	GO95 Rule 35	N/A
TREE DEFLECT TELCO LINE	B		N/A	GO95 Rule 35	N/A
TREE TO TRANSMISSION CLEARANCE	A	For RMP: "A" if tree within 5 feet of conductor for main grid transmission lines	OAR 860-024-0016(5)	GO95 Rule 35	N/A
TRANSM GROUND CLEARANCE ISSUE	A/B	"A"-priority. Engineering to evaluate. "B"-priority if so determined by engineering evaluation	N/A	GO95 Rule 18	N/A
TRANS DAMAGED C-HOOK OR PHASE FITTING	A	"A" if visible wear on c-hook or phase fitting.	N/A	GO95 Rule 18	N/A
TRANSMISSION LOW SAG ISSUE	A/B	"A"-priority. Engineering to evaluate. "B"-priority if so determined by engineering evaluation	N/A	GO95 Rule 18	N/A

TRANSMISSION ENCROACHMENT	A/B	"A"-priority if nonconforming to NESC/GO95. "B"-priority if blocking access or infringes on right of way	N/A	GO95 Rule 18	N/A
TRANSMISSION UNEVEN SAG ISSUE	A/B	"A"-priority. Engineering to evaluate. "B"-priority if so determined by engineering evaluation	N/A	GO95 Rule 18	N/A
TRANS LOOSE INSULATOR ATTACHMENT	A	Severe is "A".	N/A	GO95 Rule 18	N/A
TRANS HARDWARE NOT BONDED	B	Hardware to hardware or hardware to ground per Construction Standards.	N/A	GO95 Rule 18	N/A
TRANS-LOOSE XBRACE ATTACHMENT	A	Severe is "A".	N/A	GO95 Rule 18	N/A
TRANS-LOOSE/MISSING XBRACE CTR NUT	A	Missing is "A". Loose is "B".	N/A	GO95 Rule 18	N/A
TRANS-DAMPER MISSING/DMG/SLIPPED	A/B	Missing, damaged, or slipped damper. 10' or greater from the shoe or hanging over public area is an "A", otherwise it's a "B"	N/A	GO95 Rule 18	N/A
TRANS-HIGH VOLTAGE SIGN FADED/MISSING	B	For California see GO95HV	N/A	N/A	N/A
TRANS-COTTER KEY MISSING/WEAK	A/B	Missing is "A". Weak/deteriorated is "B".	N/A	GO95 Rule 18	N/A
TRANS-HARDWARE LOOSE	A/B	"A" if missing nuts. "B" if loose nuts. Expanded coil washer and vertical clothes pin washer are not a condition. Phase raiser covers loose or with long bolts are "B".	N/A	GO95 Rule 18	N/A
TRANS-MISSING NUTS	A/B	If jeopardizing structural integrity, "A". Otherwise "B". Missing lock nut alone not a condition	N/A	GO95 Rule 18	N/A
TRANS-SOIL ENCROACHMENT	A/D	"A"-priority if jeopardizing structural integrity. Otherwise "D" priority RMP only.	N/A	GO95 Rule 18	N/A
TRANS-PIN FALLING OUT	A/B	Severe is "A". Loose is "B".	N/A	GO95 Rule 18	N/A
TRANS-LINE INTERSECTN SIGN MISSING	A/B	"A" in RMP. "B" in PP	N/A	GO95 Rule 18	N/A
VINES CONTACTING TRANSMISSION	A	"A" if tree within 5 feet of conductor for main grid transmission lines. "A" if tree within 3 feet of conductor for local transmission lines	N/A	GO95 Rule 34, 35	NESC Rule 217A4, NESC 218A
UNDERBUILD-CROSS ARM	A/B	"B" if cross brace broken, missing or hanging loose on distribution. "A" on transmission cross arm	N/A	GO95 Rule 18	NESC Rule 252 & 012C
UNDERBUILD-DISTRIBUTION ANCHOR	A/B	Pulled or corrosive distribution anchor	N/A	GO95 Rule 18	NESC Rule 012C
UNDERBUILD-DISTRIBUTION CONDUCTOR	A/B	Distribution conductor issue	N/A	GO95 Rule 18	N/A
UNDERBUILD-GROUND BROKEN/CUT	A/B	Equipment ground on delta is an "A". Any broken ground less than 8 ft above earth is "A" or can get blown into phase conductor is an "A". Another other broken ground is	N/A	GO95 Rule 18	NESC Rule 214A5 & 095A
UNDERBUILD-ARRESTOR/CUTOUT	A/B/D	Signs of tracking or cracked porcelain is A. If jumpered out or parts missing, B. Priority D is RMP only for idle equip or porcelain cutout; note in comment field	N/A	GO95 Rule 18	NESC Rule 012C
UNDERBUILD-DISTRIBUTION GUY BROKEN	A/B	Broken distribution guy wire	N/A	GO95 Rule 18	NESC 261C2
UNDERBUILD-DISTRIBUTION GUY SLACK	A/B	Slack distribution guy wire	Policy 009 Section 3.3(d)	GO95 Rule 56.2	NESC 261A5C & 264A
UNDERBUILD-TIE WIRE BROKEN	A	If loose enough to free conductor, "A".	N/A	GO95 Rule 18	NESC Rule 214A5a & 012C
UNDERBUILD-DISTRIB. CROSSARM	A/B	Severe, "A". Moderate, "B".	N/A	GO95 Rule 44.3	NESC 261D
UNDERBUILD-MISSING HARDWARE	A/B	"A" if missing nuts. "B" if loose nuts. Expanded spring not a condition.	N/A	GO95 Rule 18	NESC Rule 012C
UNDERBUILD-INSULATOR BROKEN	A/B	See Insulator Policy 012. If tracking or actively smoking it's an A priority.	Policy No. 012	GO95 Rule 18	NESC Rule 012C & 447
UG CONDUCTOR DAMAGED	A	"A" if signs of tracking, swelling or deformation.	Policy 008	GO128 Rule 34.3	NESC Rule 012C
MISSING LIVEFRONT BARRIERS	B		Policy 008	GO128 Rule 32.7	NESC Rule 381G2
XFRM-BROKEN LATCH/HINGE/LOCK MISSING	A/D	Broken latch/hinge or missing lock on UG allowing access. Install lock at time of inspection if possible. Use D condition if lock present but missing Pentahead Bolt	Policy 008 Sections 3.1.2 and 3.1.4	GO128 34.3-C	NESC Rule 381G1 & 2
LIFTING BOLTS NOT REMOVED OR TURNED	B	Remove or turn lifting bolts at time of inspection if possible.	Policy 008	GO128 Rule 17.3	NESC Rule 012C
EXCESSIVE FOREIGN MATERIAL IN XFMR	B		Policy 008	GO128 Rule 34.3	NESC Rule 381G2
XFRM-SEVERELY RUSTED/ALLOW ACCESS	A/B	"A" if deteriorated such that it allows access. "B" if no access but rust is significant	Policy 008, Policy 009	GO128 34-3B, 35.A	NESC Rule 012C, NESC Rule 214A5
TRENCHING FROM PAD NOT PROPERLY BACKFILL	B	No differentiator as only a 'B' condition is allowed	Policy 008 Section 3.1.3	GO128 Rule 34.3	NESC Rule 321B
UG INSULATOR COVER MISSING/DAMAGED	A	"A" if signs of cover damage or missing cover.	Policy 008	GO128 Rule 32.7	NESC Rule 381G2
UG INSULATORS DAMAGED	A	"A" if signs of tracking, swelling or deformation.	Policy 008	GO128 Rule 34.3	NESC Rule 012C
UG INSULATORS CONTAMINATED /DIRTY	A/B	"A" if signs of tracking, swelling or deformation. "B" if contaminated or dirty	Policy 008	GO128 Rule 34.3	NESC Rule 012C
UG-PRIMARY ELBOW	A	If signs of tracking, swelling or deformation A.	Policy 008	GO128 Rule 34.3	NESC 447
UG SUBMERABLE SHROUD DAMAGED/SLID	A/B	"A" if access to conductors or bushings.	Policy 008	GO128 Rule 32.7	NESC Rule 012C
FRACTURED/DAMGED POWER SPRING	A	"A" if signs of tracking, swelling or deformation.	Policy 008	GO128 Rule 34.3	NESC Rule 012C
UG INSULATORS /TERMINATORS TRACKING	A	"A" if signs of tracking, swelling or deformation.	Policy 008	GO128 Rule 34.3	NESC Rule 012C
UG VAULT MISSING SECURING BOLTS/ACCSSABL	A	"A" if vaults is not secured and is accessable.	Policy 008	GO128 34.3-C	NESC Rule 381G1 & 2
UNCOVERED TANK MOUNTED ARRESTER BOLTS	D	For information only; not a condition if configuration does not require avian covers (i.e. raptor framing)	N/A	GO95 Section I-3	NESC 012C
UNCOVERED ARRESTER	D	For information only; not a condition if configuration does not require avian covers (i.e. raptor framing)	N/A	GO95 Section I-3	NESC 012C
UNCOVERED PRIMARY BUSHING	D	For information only; not a condition if configuration does not require avian covers (i.e. raptor framing)	N/A	GO95 Rule 18	NESC 012C

UNCOVERED CUTOUT	D	For information only; not a condition if configuration does not require avian covers (i.e. raptor framing)	N/A	GO95 Section I-3	NESC 012C
UNCOVERED INSULATOR	D	For information only; not a condition if configuration does not require avian covers (i.e. raptor framing)	N/A	GO95 Section I-3	NESC 012C
BARE JUMPERS	D	For information only	N/A	GO95 Section I-3	NESC 012C
UNIGROUND-BROKEN/MISSING MOLDING	B	(For CA see GO95MLD.)	N/A	N/A	NESC Rule 093D1 & 093D3
UNIGROUND-GRD ROD SEPARATION <20FT	B	California Requirement Is 6' Between Ground Rods. All Nesc States: 20FT From Buried Comm Cables	N/A	GO95 34C3(a)	NESC 097F
UNIGROUND-SINGLE GROUND	B		N/A	GO95 Rule 33.3B	NESC Rule 097A, 097B & 097C
INSP ISSUE - VEGETATION	B	Inspection obstructed by vegetation	Policy 361, 298, 298 & 013	GO95 Rule 31.2	NESC 121A, NESC 213, NESC 312
WASHOUT	A/B	Pole needs rocks or other appropriate backfill. "A" if severe.	N/A	GO95 Rule 18	NESC Rule 012C
WRAPPED POLE - MESH TYPE FIRE	D	Condition assigned to identify pole wrapping; for information only	N/A	N/A	N/A
WRAPPED POLE - NON-MESH FIRE	D	Condition assigned to identify pole wrapping; for information only	N/A	N/A	N/A
XARM-CROSS BRACE BROKEN/MISSING/LOOSE	A/B	"B" if cross arm brace broken, missing or hanging loose on distribution. "A" if transmission cross arm broken or missing. If loose transmission hardware, use	N/A	GO95 Rule 18	NESC 261D
ARM SPLIT/CRACKED/ROTTEN/TWISTED/TRACKNG	A/B	"A" if severe. "B" if moderate.	N/A	GO95 Rule 18	NESC 261D
XARM-SQUATTER PIN	B	"B" if insulator is sitting on cross arm.	N/A	GO95 Rule 18	NESC Rule 012C & 252
GROUND BROKEN/MISSING/INSUFFICIENT #	B	No differentiator as only a 'B' condition is allowed	Policy 008	GO95 Rule 58.2A(3)	NESC Rule 314, 374, 384
XFRM-LOOSE/MISSING BOLTS/BRACKET	A/B	"A" if hardware is missing. "B" if hardware is loose.	Policy 009	GO95 Rule 18 A-1	NESC Rule 012C
XFRM-BUSHING/INSULATOR BROKEN	A/B	"A" if severe. "B" if moderate.	Policy 009	GO95 Rule 18 A-1	NESC Rule 012C

GRANDFATHERABLE	ENERGY_RELEASE_RISK	HIGH_IMPEDANCE	RELIABILITY	CREW	RESPONSIBLE_PARTY
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	YES	YES	3 MAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	YES	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	NO	YES	YES	2 MAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	NO	NO	YES	SINGLEMAN	POWER
NO	NO	NO	YES	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	NO	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	2 MAN	POWER
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	YES	YES	2 MAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER

NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	NO	NO	YES	3 MAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	YES	YES	4 MAN	POWER
NO	YES	YES	YES	4 MAN	POWER
NO	NO	NO	YES	4 MAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
YES	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	CUSTOMER	CUSTOMER
NO	NO	NO	NO	CUSTOMER	CUSTOMER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	YES	YES	2 MAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER

NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	3 MAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	YES	YES	SINGLEMAN	POWER
NO	NO	YES	YES	SINGLEMAN	POWER
YES	NO	NO	NO	CUSTOMER	CUSTOMER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	COMMUNICATIONS	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	NO	NO	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	YES	YES	2 MAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER

NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	NO	NO	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	3 MAN	POWER
NO	YES	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	YES	YES	3 MAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	ESTIMATOR	POWER
NO	YES	NO	YES	ESTIMATOR	POWER
NO	YES	NO	YES	ESTIMATOR	POWER
NO	YES	NO	YES	ESTIMATOR	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	YES	YES	3 MAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER

NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	ESTIMATOR	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
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NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
YES	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	YES	YES	SINGLEMAN	POWER
NO	YES	YES	YES	SINGLEMAN	POWER
NO	NO	NO	NO	COMMUNICATIONS	COMMUNICATIONS
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	YES	ESTIMATOR	POWER
NO	NO	NO	NO	SINGLEMAN	POWER

NO	NO	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	YES	NO	NO	SINGLEMAN	POWER
NO	NO	NO	NO	SINGLEMAN	POWER
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December 20, 2024 Updates

The following changes were made to make Revision 28

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Policy

VISUAL ASSURANCE INSPECTIONS — SAFETY PATROL OF TRANSMISSION AND DISTRIBUTION LINES

Asset Management Policy No. 011

Author:	Avery Masanga
Approval:	Alex Vaz
Authoring Department:	Asset Management
Approved Location:	Pdxshrn104\shr04\Eng\Publications\FPP\DIS\POL
File Number-Name:	011-Visual Assurance Inspections.docx
Revision Number	R15
Revision date:	2/25/2025
Summary of Policy:	Provide guidance and requirements for visual assurance inspections, also known as patrol inspections, of transmission and distribution lines.
Affected Departments:	Transmission & Distribution Operations (Line) Field Inspection Support

Document Security Category			
	Confidential		External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
1	1/3/2003	Original policy, written by Chuck Wright, lead transmission engineer
2	2/13/04	
3	6/26/06	
4	2/14/07	
5	12/18/07	
6	9/26/08	
7	10/25/12	Priority A and B definitions have been clarified.
8	5/9/14	Updated to reflect new/revised policies/references/priorities/correction timeframes
9	8/8/18	Updated to remove California, which is now referenced in Policy 342
10	10/18/18	Removed subsection 5.11
11	2/19/21	Language about imminent threat has been added to the scope.
12	5/23/23	Reviewed to ensure compliance with NESC 2023.
13	9/4/24	Updated reference list.
14	1/22/25	Removed underground facilities, updated language in each section to more accurately reflect visual assurance inspections and updated to include California.
15	2/25/25	Added a note that out-of-service facilities are to be inspected in the same manner as in-service facilities.

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VISUAL ASSURANCE INSPECTIONS — SAFETY PATROL OF TRANSMISSION AND DISTRIBUTION LINES

Asset Management Policy No. 011

1 Scope and Work Practices

The following policies and work practices apply to both PacifiCorp employees and contractors performing patrol inspections on PacifiCorp's transmission and distribution systems located in California, Oregon, Washington, Utah, Idaho, and Wyoming.

1.1 Visual Assurance Inspection

Visual assurance inspections are brief assessments conducted from a reasonable vantage point, focusing on identifying:

- Obvious damage or defects that may compromise system integrity.
- Potential ignition risks or other safety hazards.
- Significant right-of-way encroachments that could endanger the public or the system.

These inspections are also referred to as Patrol Inspection in Oregon and Safety Patrols in California. Visual assurance inspections are not intended to replace detailed evaluations, which are conducted under *Policy 009 – Detailed Inspections for T&D Lines*.

While primarily focused on transmission and distribution facilities, visual assurance inspections may include secondary services, such as household connections, if they are readily visible during the course of the patrol inspection.

1.2 Reporting and Documentation

All inspections and any identified defects or conditions must be documented in the Facility Point Inspection (FPI) system:

- "SAFETY" Code: Used when no issues are observed.
- "SAFETYEX" Code: Used to document identified issues, including condition codes and any relevant comments.

By uploading a completed inspection into the FPI system, inspectors affirm that they have conducted the inspection in compliance with policy requirements and have accurately recorded all observed conditions. Nonconforming items must be flagged as out of compliance and recorded appropriately.

For every inspection performed, the **date** and **inspector's name** must be entered in the FPI system for the corresponding facility points.

1.3 Condition Code and Prioritization

The FPI system assigns condition codes to help prioritize repair work. Each identified condition must be assigned a priority level in line with the referenced policies. Once a condition is corrected, the FPI database must be updated to reflect the change.

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2 General References

National Electrical Safety Code

State of Oregon Administrative Rules 860-024

California General Orders 95, 165, and 128

PacifiCorp Procedure 069, *Clearance Table, Grandfathering Matrix, Dropdown Codes*

PacifiCorp Policy 009, *Detailed Inspections*

PacifiCorp Policy 013, *Wood Pole Test and Treat*

PacifiCorp Policy 292, *Transmission & Distribution System Condition Priorities and Correction Timeframes*

3 Inspection Protocals for Transmission and Distribution Systems

The inspection cycle for transmission and distribution systems shall be as recommended by asset management in Policy 001. These cycles are based on statutory requirements, as well as key factors including environmental conditions, asset age, performance history, and operational significance. It is recognized that many of the facilities are inspected by qualified employees or contractors and be performed either by air (helicopter) or ground patrol.

Facilities temporarily out of service shall be inspected in the same general manner as in-service facilities to prevent hazards, per NESC Rule 214.B.2 and GO-95 Rule 31.2. Facilities permanently abandoned shall be removed or inspected and maintained in a safe condition, per NESC Rule 214.B.3 and GO-95 Rule 31.6.

4 Hazard Conditions to be Reported: Transmission and Distribution Systems

The following is a minimum list of potentially hazardous conditions to be reported for both the transmission and distribution systems. These inspections align with the intent of National Electric Safety Code (NESC) and corresponding regulatory requirements in each state, including California's GO 95, which focuses on identifying obvious structural issues and hazards through a basic visual inspection. These inspections may be conducted as a stand-alone activity or integrated into other company operations.

4.1 Poles

- Damaged, leaning, or climbable poles
- Split or decayed tops

4.2 Crossarms and Insulators

- Split, broken, or burned crossarms
- Missing or hanging braces
- Missing, broken, or loose insulators
- Broken tie wires

4.3 Conductors

- Improper sag
- Floaters

- Loose tails
- Frayed or broken strands
- Public accessibility

4.4 Clearances

- Significant clearance violations identifiable through visual inspection that present a public safety risk

4.5 Transformers and Other Equipment

- Leaks or other signs of damage or overheating
- Not secure to pole

4.6 Guys

- Broken or without guards in pedestrian area
- Visible slack with potential to contact energized facilities

4.7 Risers

- Conduits crushed, broken, or joints open
- Climbable risers
- Conduits not secured to pole

4.8 Services

- Inadequate clearances from buildings, windows, balconies, roads, and walkways, identifiable through visual inspection, which pose a public safety risk
- Service coils tied to pole
- Conductor insulation abrasion
- Broken messenger wire

4.9 Trees

- Climbable trees
- Trees or limbs showing evidence of incidental or persistent contact

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Procedure

Helicopter Standard Operating Procedure for Line Inspections

Facility Inspection Procedure No. 203

Author:	Helicopter Standards committee: Tori Bennett, Matthew Rolow, Scott Wardrop, Cameron Campbell, Michael Clark, Ray Walker, Christopher Canty, Larry Ezell
Approval:	Tori Bennett
Authoring department:	Facility Inspection
Approved file location:	J:\Eng\Publications\FPP\XMSN\PRO
File number-name:	203-Helicopter Operating Procedure for Line Inspections.docx
Revision number:	3
Revision date:	1/8/2018

Document Security Category			
	Confidential		External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
0	4/23/03	Initial issue.
1	6/1/09	Rev. 1.
2	9/18/13	Department approver was updated, and an attachment for overdue classic helicopters was added.
3	1/8/18	Training roster updated, patrolman equipment list removed – see tailboard, Grid email added and fax deleted, aircraft familiarization - survival equipment - weather monitoring is helicopter vendor responsibility, updated procedures for overdue aircraft vendors.

Procedure

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Helicopter Standard Operating Procedure for Line Inspections

Facility Inspection Procedure No. 203

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Helicopter Standard Operating Procedure for Line Inspections

Facility Inspection Procedure No. 203

1 Preface

This standard operating procedure is designed to provide safe operating practices for air inspection of PacifiCorp's transmission and distribution facilities while operating in the wire environment.

Special operations including crew transfer to remote locations are not covered within this document. Special operations must be coordinated with the Pilot In Command (PIC).

Standards have been established for this document using federal regulations as defined in Code of Federal Regulations (CFR) title 14, 1.1 and Part 91.

PacifiCorp employees acting in this assignment are designated crew members aboard the aircraft and the following definitions apply, relating to crew member and operational environment:

- Crew member means: Any person assigned to perform duty in an aircraft during flight time as described in CFR title 14, Part 1.1. See attached document #1.
- Alcohol or drug use including nausea medications are governed under the following Federal Air Regulations: CFR title 14. Part 91.17 and is further defined under (Crew Pre-Flight Checklist) section of this document. See attached document #2.
- Only approved helicopter vendors may be used for this work. An approved vendor list may be found on the company intranet: http://idoc.pacificorp.us/policies_and_procedures/eamp/transmission/fpp/hfpp.html.

2 Pilot In Command

The responsibility and authority of the pilot in command is defined in the Code of Federal Regulations (CFR) Title 14, Part 91.3 as follows:

- The pilot in command of an aircraft is directly responsible for, and is the final authority as to, the operation of that aircraft.
- In an in-flight emergency requiring immediate action, the pilot in command may deviate from any rule of this part to the extent required to meet that emergency.
- Each pilot in command who deviates from a rule under paragraph (b) of this section shall, upon the request of the Administrator, send a written report of that deviation to the Administrator.

3 Qualified Employees and Training

The qualified employees designated to perform this job function are Line Patrolman and Lineman who have received adequate training for wire strike avoidance and helicopter flight operations.

All in-flight training must be performed by a Line Patrolman or former Line Patrolman who possesses adequate knowledge in Crew Resource Management and flight procedures for line inspection.

Training requirements are as follows:

- In-Flight Training: A minimum of 16 flight hours is required for a Line Patrolman or Lineman to occupy the front seat for line inspection and must be documented on PacifiCorp training roster form, PPWTC00327
- Classroom-Wire Strike Avoidance Training: Classroom training on Wire Strike Avoidance and Crew Resource Management *must be supplemented when training is available.*
- Employees must attend recurrent classroom training when offered to maintain qualified status.

4 Wire Environment

The definition of the wire environment pertaining to this document is as follows:

- Flat Ground: 250–300 feet above ground level (AGL); add 100 feet over line crossings.
- Non-Flat Terrain: Rivers, canyons, valleys, fjords; anywhere below the ridge tops is considered the wire environment until you further define and confirm where the wire actually is.
- In the vicinity of towers and structures.

5 Pre-Inspection Planning

1. Scheduling: Best routing to maximize efficiency of aircraft and minimize ferry time.
2. Preflight Contacts-Law Enforcement: Notify local law enforcement agency about intended flight operations. Provide aircraft description, “N” number and aircraft call sign if assigned.
3. Preflight Contacts-Industrial/Commercial: Contact appropriate Commercial and Industrial account manager, who will notify industrial/commercial customers of fly over. Notify county sheriff as needed.
4. Preflight Contacts-Sensitive Installations: Contact responsible security entity and provide required information for intended operation. (Nuclear facilities, prisons, etc.)
5. Additional Passenger(s): Additional passenger(s) may be carried for a valid business reason if approved by the Pilot In Command (PIC) and if gross weight at the altitudes and temperatures expected on the patrol route will accommodate the additional load without compromising aircraft performance or patrol efficiency. Rocky Mountain Power will follow the APM requirements.
6. Helicopter Type: Convey to the Pilot In Command (PIC) all known information pertaining to route, terrain, elevations, and weight of patrolman, equipment and additional passenger(s). Decision as to type of helicopter (single/twin engine) will be made by both parties to provide adequate safety margins for the conditions expected during the patrol mission.

6 Pre-Flight Procedures

1. Personal Check List (Fitness for Flight): Each patrolman must evaluate his own fitness for flight prior to commencing transmission patrol operations. All crew members are governed under Code of Federal Regulations (CFR) title 14, Part 91.17. See attached document #2.

2. Routing/ Temporary Flight Restrictions: Review routing to maximize efficiency of aircraft and minimize ferry time. Discuss routing with Pilot In Command (PIC) utilizing aeronautical sectional chart. Pilot (PIC) is responsible for Temporary Flight Restrictions (TFR) briefing from FAA that could impact operations. Notify pilot of any known concerns along intended route of flight. This could include predominate crosswinds/downdrafts known to exist from previous flights.
3. Weather Review/Wind: Pilot In Command (PIC) to obtain weather information and review with crew. Flight crew will make necessary decisions affecting route plan and execution of flight. Line patrol in sustained wind conditions exceeding 20 knots should be avoided.
4. Fuel Management: Determine with Pilot In Command (PIC) amount of fuel needed on board to complete task without compromising reserve supply. Verify sufficient fuel quantity.
5. Flight Plan/Flight Follow and Notification Procedures: A flight plan ***must*** be filed with Grid Ops dispatch center. Provide all information that is detailed on the attached *Helicopter Flight Plan*. For long missions, *Flight Follow* may be used and notification given to dispatch following completion of a line and informing them that next leg of plan is starting. Dispatch should have all vendor information including emergency contact numbers. All flight following will be performed by Grid OPS dispatchers. Contact numbers for Grid Ops are: EMAIL; Transmission Grid Operators. Phone East: (801) 220-2453 / 503) 251-5250, West: (503) 251-5230 or (800) 250-5523.

   Inform Grid Ops of any air patrol within the proximity of thermal and hydro plants and foreign utilities. (See attachment #4)
6. Noise Abatement for Sensitive Areas: Determine areas where noise complaints have been voiced and plan to avoid if possible.
7. Flight Time Limitations: Flying in the wire environment should not exceed six hours per day. This does not include ferry time.
8. Personal Protective Equipment: Per APMs and safety orders
9. Equipment Storage: Ensure that all equipment is stowed in a position that will be easily accessible for use but will not interfere with the following:
   a) Operation of flight controls
   b) Emergency egress
   c) Crew safety

7 In-Flight Operating Procedures

1. Initiate Inspection: Use GPS or land reference to guide pilot to starting point on line. Stay high at initial inspection location and identify any obstacles, crossings and positively locate initial structure. Both pilot and patrolman must agree that all concerns are identified before descent.
2. Communication: Follow crew communication guidelines as provided in wire strike avoidance training and developed by your crew. Flight crew must acknowledge calling out of turns, crossings and other hazards during all phases of the flight.
3. Logging Data: Coordinate with pilot the best way for logging data. The preferred practice is to exit the wire environment before making any notes.

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4. Flight Follow: When using flight follow, notify Grid Ops when a line segment is completed. Verify with Grid Ops that you are starting the next leg of your filed flight plan. **Any deviation from flight plan requires contact with Grid Ops.**
5. Extend Flight Plan: Notify Grid Ops if the possibility exists the flight will be overdue.
6. Hot Entry/Exit: Entering and exiting the helicopter when running is under the direct supervision of the Pilot In Command (PIC).
7. Confined/Slope/Pinnacle Landings: All off-airport landing areas require increased awareness due to unseen hazards. If an off-airport landing is needed, the crew will determine the most suitable landing zone. Pilot In Command (PIC) has final authority for decision.
8. Avoiding Fatigue: Pilot and patrolmen are responsible for recognizing the signs of fatigue in a fellow crew member and taking the appropriate action when fatigue becomes a factor.

8 Post-Flight Procedures

1. Terminate Flight Plan: Close flight plan with the grid operator and the local law enforcement dispatcher if filed.
2. Flight review: Crew should review at the end of the flight any areas of concern, including communication and any other factor encountered during the flight.
3. Personal Equipment: Check aircraft for all personal equipment and company documentation.
4. Aircraft Security: When leaving aircraft unattended, secure ship and remove personal equipment and sensitive documents.
5. File completed Tailboard and Risk Assessment document.

Procedure

Attachment 1 – Code of Federal Regulations Definition of Crewmember

Code of Federal Regulations
Title 14, Volume 1
Revised as of January 1, 2004
From the U.S. Government Printing Office via GPO Access
CITE: 14CFR1.1

TITLE 14—AERONAUTICS AND SPACE

CHAPTER I—FEDERAL AVIATION ADMINISTRATION, DEPARTMENT OF TRANSPORTATION

PART 1—DEFINITIONS AND ABBREVIATIONS—Table of Contents

Sec. 1.1 General definitions.

Crewmember means a person assigned to perform duty in an aircraft during flight time.

Attachment 2 – Code of Federal Regulations Alcohol and Drug Policy

Code of Federal Regulations
Title 14, Part 91 GENERAL OPERATING AND FLIGHT RULES
91.17 Alcohol or drugs.

(a) No person may act or attempt to act as a crewmember of a civil aircraft—

(1) Within 8 hours after the consumption of any alcoholic beverage;

(2) While under the influence of alcohol;

(3) While using any drug that affects the person's faculties in any way contrary to safety, or:

(4) While having an alcohol concentration of 0.04 or greater in a blood or breath specimen. Alcohol concentration means grams of alcohol per deciliter of blood or grams of alcohol per 210 liters of breath.

(b) Except in an emergency, no pilot of a civil aircraft may allow a person who appears to be intoxicated or who demonstrates by manner or physical indications that the individual is under the influence of drugs (except a medical patient under proper care) to be carried in that aircraft.

(c) A crewmember shall do the following:

(1) On request of a law enforcement officer, submit to a test to indicate the alcohol concentration in the blood or breath, when—

(i) The law enforcement officer is authorized under State or local law to conduct the test or to have the test conducted; and

(ii) The law enforcement officer is requesting submission to the test to investigate a suspected violation of State or local law governing the same or substantially similar conduct prohibited by paragraph (a)(1), (a)(2), or (a)(4) of this section.

(2) Whenever the FAA has a reasonable basis to believe that a person may have violated paragraph (a)(1), (a)(2), or (a)(4) of this section, on request of the FAA, that person must furnish to the FAA the results, or authorize any clinic, hospital, or doctor, or other person to release to the FAA, the results of each test taken within 4 hours after acting or attempting to act as a crewmember that indicates an alcohol concentration in the blood or breath specimen.

(d) Whenever the Administrator has a reasonable basis to believe that a person may have violated paragraph (a)(3) of this section, that person shall, upon request by the Administrator, furnish the Administrator, or authorize any clinic, hospital, doctor, or other person to release to the Administrator, the results of each test taken within 4 hours after acting or attempting to act as a crewmember that indicates the presence of any drugs in the body.

(e) Any test information obtained by the Administrator under paragraph (c) or (d) of this section may be evaluated in determining a person's qualifications for any airman certificate or possible violations of this chapter and may be used as evidence in any legal proceeding under section 602, 609, or 901 of the Federal Aviation Act of 1958.

[Doc. No. 18334, 54 FR 34292, Aug. 18, 1989, as amended by Amdt. 91–291, June 21, 2006]

Procedure

Attachment 3 – Helicopter Flight Plan

The most current version of the helicopter flight plan is posted at: http://idoc.pacificorp.us/serving_customers/ppto/fo/rmplpi/helicopter-forms--policies-and-procedures.html.

Attachment 4 – Line Patrolmen Air Patrol Notification Procedure

Purpose: Notify all parties (dispatch, hydro and thermal power plants) of air patrols throughout PacifiCorp's system.

Line Patrolman

Line Patrolmen will notify Grid operations of all aerial patrols scheduled or emergency

Contact number: West Patrols 503-251-5230
East Patrols 503-251-5250

EMAIL flight plans to: Transmission Grid Operators

Grid Operators

Notify all thermal and hydro power plants of flight plans and schedule

Notify foreign utilities, Pacific Northwestern Security Coordinator (PNSC), and Western Electricity Coordination Council (WECC) as necessary.

Notify commercial and trading generation desk

Notify region dispatcher (this allows coordination of local grid patrols if necessary)

Plant Shift Supervisors

Notify operations and plant personnel of flights in close proximity of plant facilities

Insure the information is passed on to plant personnel as shift changes occur.

Attachment 5 – Overdue Aircraft Procedures for Helicopter Services 2017–2019 contract period.

When the aircraft is assumed to be missing the grid operator will initiate the following procedures:

When aircraft is between 30 minutes and 1 hour overdue:

1. Continue to attempt contact with the flight crew by telephone and over radio frequencies.
2. Notify the managers and line crews in the area that the aircraft would have been operating.

When aircraft is more than 1 hour overdue:

1. Contact the last known airport.
2. Contact the destination airport.
3. Notify one person at the following numbers:

Contractor	Vendor #	Contact	Email	Phone #
Classic Helicopters	400558	Orin Kinghorn	skinghorn@classicaviation.net	801-295-5700
Hillsboro	116407	Franz Bergtold	fbergtold@hillsboroaviation.com	503-648-2831
Mountain West Helicopter	413914	Brian Burr	bjburr@mwheli.com	801-216-4001
Salmon River Helicopter		Niki Schacher	salmonriverheli@gmail.com	208-628-3515
Timberland	124697	Mark Gibson	tllmark@mindspring.com	541-488-2880
Wilson Construction	113371	Jenny Kratzke	jkratzke@wilsonconst.com	503-263-6882
Winco	148620	Mike Patton	m.patton@wincoservices.com	503-678-6060

4. Contact the sheriff department(s) in the area(s) of operations.

   Give the sheriff's dispatch the following information.
   a. The aircraft registration number.
   b. The number of people on board.
   c. The color of the aircraft.
   d. The last known position, and the time of contact at that position.
   e. The route that the aircraft was following.

5. If no one listed above can be reached, contact the FAA Flight Service Station at 1(800) 992-7433, and report the overdue aircraft. Then follow their instructions.

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Attachment 6 – Training Attendance Roster (submit to HR Svc Center, LCT 1800)

All Fields Are REQUIRED – Call 503.813.5955 With Questions					
Training Date:		**Start Time:**		**End Time:**	
Course Title:	**Helicopter Cockpit Flight Training (16 Hours Flight Time)**				
Instructor:				**PPW #:**	**PPWTC00327**
Training Location:					
Submitted By:					

	Emp. #	Print Name	Signature (REQUIRED)
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HR USE ONLY *SAP Input By:* *BE #:* *Date:*

Procedure

Helicopter Tailboard:

http://idoc.pacificorp.us/content/dam/intranet/doc/has/safety_and_occupational_health/rmphs/Tailboard_TandD_Helicopter.pdf

Helicopter Flight Plan:

http://idoc.pacificorp.us/policies_and_procedures/eamp/transmission/fpp/hfpp.html

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

WOOD POLE TEST & TREATMENT
TRANSMISSION AND DISTRIBUTION LINES
Asset Management Policy 013

Author:	Avery Masanga
Approval:	Alex Vaz
Authoring Department:	Asset Management
Approved Location:	DFS\PDXCO\SHR04\Publications\FPP\DIS\POL
File Number-Name:	013-Wood Pole Test and Treatment.docx
Revision No.	22
Revision Date:	1/22/2025

Document Security Category			
	Confidential	X	External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
11	2/15/2012	A-Priority to 33%. No fumigants in dist poles in Zone 1 and WA. Add accelerant.
12	8/14/2012	No intrusive test unless decayed in ID, UT, WA, WY. Differentiate transmission and distribution pole testing.
13	10/23/12	Clarify A and B priorities. Modify Tables 1A and 1B.
14	2/15/2013	Eliminate strength at groundline for reinforcing. Update Tables 1A and 1B.
15	6/10/2014	Move CA and OR to separate Policies. Add References. Delete Tables 1A and 1B.
16	1/13/2017	Added inspection acknowledgement to section 3
17	2/9/2022	Updated information on treatment preservatives.
18	2/24/2022	Additional modifications to treatment preservative information.
19	3/23/2022	Additional modifications to treatment preservative information in the Appendices
20	8/30/2024	Added additional options for external pole treatment wrap.
21	9/4/2024	Updated reference list.
22	1/22/2025	Applied policy to all PacifiCorp states. Policy 298 and 299 discontinued.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

WOOD POLE TEST & TREATMENT
TRANSMISSION AND DISTRIBUTION LINES
Asset Management Policy No. 013

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Policy

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

WOOD POLE TEST & TREATMENT
TRANSMISSION AND DISTRIBUTION LINES
Asset Management Policy No. 013

1 Scope

The policies, procedures and work practices that follow apply to all PacifiCorp employees and contract employees who perform inspections on PacifiCorp's transmission and distribution systems. The purpose of this policy is to present methods and procedures for utility pole inspection and maintenance; this includes testing poles for continued serviceability and providing information/guidance on preventive and remedial treatment.

All poles are to be inspected by trained personnel. Any pole or item found with a potential of failing shall be considered out of compliance and be recorded into PacifiCorp's Facility Point Inspection (FPI) system. The appropriate coding for the condition discovered shall be entered along with any appropriate comments. The FPI system allows codes to be assigned to the conditions that are used for prioritizing subsequent repair work. Each condition shall have the appropriate priority code assigned in accordance with PacifiCorp policies and procedures. After a nonconforming condition has been corrected, the FPI database must be updated to reflect the changes.

All poles will be inspected in accordance with Section 5.2.1 for transmission poles, and per Section 5.2.2 for distribution poles. All poles will be designated as either Satisfactory, Reject/Reinforceable, or Reject/Replace. It is intended that poles deemed Reject/ Reinforceable be reinforced in accordance with PacifiCorp Policy 014, *Wood Pole Reinforcing Using Steel Reinforcers Transmission and Distribution Lines*. However, replacement versus reinforcement will ultimately be a business unit decision at the time the work is performed due to ensuing engineering assessments, possible additional pole damage after the initial inspection, and other factors.

Personnel performing inspections shall follow and comply with all federal, state, and local requirements and strictly adhere to all PacifiCorp's policies and procedures.

2 General References

National Electrical Safety Code (NESC) Rules

California General Orders 95 and 165 (GO 95 and GO 165)

PacifiCorp Procedure 069, *Clearance Table, Grandfathering Matrix, FAQ's, Codes*

PacifiCorp Policy 011, *Visual Assurance Inspections for T & D Lines*

PacifiCorp Policy 009, *Detailed Inspections T & D Lines* PacifiCorp

Policy 292, *Transmission & Distribution System Condition Priorities and Correction Timeframes*

PacifiCorp Policy 014, *Wood Pole Reinforcing*

PacifiCorp Construction Standard EB 141, *Poles, Reinforcing*

Berkshire Hathaway Energy, Specification EBU-PL-S03, *Supplemental Wood Pole Test and Treatment – Distribution and Transmission Poles*

3 Treatment Cycles and Inspection Records

The inspection cycle for test and treatment of wood poles shall be recommended by asset management. The cycles are based on statutory requirements in the various states served as well as age, climate, location, performance history, and other factors associated with these assets.

The results of the pole testing activity as well as any appropriate comments such as shell thickness, decay severity, preservatives applied, and other pertinent information shall be entered into the company's FPI system. The date of the inspection and name of inspector shall be entered in the FPI system for all facility points inspected. Upon correction of the condition, the FPI system shall be updated accordingly.

By entering a completed inspection, which is uploaded into the FPI system, the inspector is confirming that they have performed the inspection per the applicable requirements of this policy including recording any conditions found that require corrective maintenance.

All pole inspection records must be retained for the life of the pole.

4 General

4.1 Personnel Requirements

The quality and effectiveness of a pole inspection and treatment program is highly influenced by the experience of the personnel performing the inspection. Determination of remaining pole strength and serviceability is not an exact science, and there is no substitute for the good judgment of an experienced field pole inspector. Therefore, all pole inspection and treating specialists shall be experienced pole inspectors.

Supervisors of pole inspecting personnel shall have inspection and treatment experience that includes all wood pole species used by PacifiCorp. Each inspector shall have sufficient training and knowledge to satisfactorily determine the serviceability of wood poles.

4.2 Permits

All permits required by federal, state, and local agencies necessary for application of treatment preservatives and sterilants shall be obtained before any pole treatment is performed.

4.3 Right-of-Way or Easements

All rights-of-way or easements for the line equipment under inspection shall be verified by PacifiCorp before proceeding with any pole inspection or treatment. Pole-inspection supervisors shall comply with all reasonable requests of landowners and tenants relative to access to rights-of-way or easement.

4.4 Safety

Employees shall conduct all work with due regard to adequate safety and sanitary requirements and shall maintain all plant and equipment in safe condition. All procedures and precautions involved in the safe handling and use of treatment chemicals shall be observed. Inspectors shall review all safety data sheets and manufacturer's labels before using any treatment preservatives.

5 Inspection / Testing of Poles

5.1 Inspection Type Requirements

5.1.1 Detailed Inspections

A detailed inspection of each structure shall be completed per PacifiCorp Policy 009, *Detailed Inspections – T & D Lines*.

5.1.2 Inspection of Pole Top

The pole top shall be visually inspected to determine its general condition. If it is not satisfactory, then it shall be determined if the pole can be framed down for a bad top while still meeting clearance requirements. If not, the pole should be classified as Reject/Replace and no further inspection, testing, or treatment should be performed on that pole. Personnel performing inspections should not climb poles without prior approval from PacifiCorp.

5.1.3 Sound Test

A pole-sound test is performed on all poles to locate external and internal decay pockets. The pole shall be tapped with a metal hammer from the groundline to as high as the inspector can reach to reveal soft spots or hollow-sounding areas. An experienced inspector can obtain significant information about the pole by listening to the sounds. Internal decay pockets cause a sound that is dull compared to the crisp sound of a solid pole section. In addition, the hammer rebounds more from a solid pole than when hitting a section that has an internal decay pocket. If the pole has been excavated in accordance with Section 5.3, then the sounding shall be performed starting as far below the groundline as practical.

5.1.4 Bore Inspection

If decay is suspected, inspection holes shall be drilled to determine the extent of the internal decay. An experienced inspector will notice a change in resistance against the drill when it contacts decayed wood. Borings shall be performed for transmission and distribution poles as follows:

Transmission Poles: If sounding the pole does not indicate internal decay is present, the pole shall be drilled for preservative treatment in accordance with Section 7.1. If decay is found during treatment hole drilling, then evaluate the pole's condition in accordance with Section 6. If the pole condition is Satisfactory, apply treatment to internal pockets/void per Section 7.4.

Distribution Poles: If sounding the pole does not indicate internal decay is present, then no further action is necessary. If sounding indicates internal decay is present, then one bore (inspection hole) should be drilled to evaluate the pole condition in accordance with Section 6. All inspection holes should be plugged with plastic plugs. Unless directed by asset management, distribution poles should not receive preventive treatment.

Poles utilizing wood stubs shall have both the pole and the stub inspected and sounded as above. Additionally, they shall both be drilled at the band locations. If there is any decay in a wood stub it shall be classified as Reject/Replace. Poles utilizing steel reinforcers shall be drilled at the band locations.

Poles not owned by PacifiCorp should be visually inspected only. No sound or bore inspection should be performed on poles owned by others. In California and Oregon, foreign-owned distribution poles should be bored and shall receive sterilization of the inspection hole only.

5.1.5 Through-Bore Pole

A through-bore pole has had preservative treatment applied by the pole manufacturer via multiple horizontally drilled small holes. For the purposes of this policy, a through-bore is defined as any bore that goes all the way through the pole. Through-bored poles shall be inspected above the through-bore area. The top of the through-bore area is approximately 4 feet above the groundline for transmission poles and three feet for distribution poles.

5.1.6 Climbing Inspections (Optional)

5.1.6.1 Communications Level

The inspection cycles and locations for communications-level climbing inspections shall be as directed by asset management. Climbing inspections shall include sounding, boring, and treatment application, with the same requirements utilized for the pole inspection requirements included in this policy with the exception of bore hole location and spacing. For climbing inspections, a single bore spaced every 5 feet up the pole to the communications level shall be made. If at any point decay is found that would classify the pole as a reject, then no further climbing or testing is to be performed and the pole will be recorded as a bad order pole as appropriate.

5.1.6.2 Inspector-Recommended GO 95 and NESC

Climbing/bucket truck inspections may also be authorized by PacifiCorp if an inspector detects damage such as a woodpecker hole or a cracked or burned pole that may result in a possible GO 95 nonconformance strength pole, and the inspector is unable to determine the extent of the damage from the ground. If the pole's integrity is in doubt, or if a climbing space obstruction exists, then the pole should not be climbed and a bucket truck inspection should be scheduled.

5.2 Inspection/Excavation/Bore by Pole Species

Transmission and distribution poles, including guy stubs, shall receive test and treatment as follows:

5.2.1 Transmission Poles

Transmission poles, including guy stubs, shall receive test and treatment as follows and per Section 7. Any new inspection hole shall be sterilized. Coastal is defined as being within 30 miles of the Pacific Ocean.

1. Poles 10 years old or newer are to be inspected and sounded only. No excavation, boring, or treatment is required. For California, poles will have an intrusive test at the next pole inspection test and treat cycle if they are four years or newer.
2. Through-bore poles shall be inspected and sounded only.

3. Non-through-bore poles set in concrete/asphalt shall be inspected, sounded, and shall be bored from groundline to below groundline.
4. Douglas fir and larch poles shall be partially excavated, then sounded, bored, and treated.
5. Western red cedar poles shall be partially excavated, sounded, bored, and treated. Poles over 20 years of age that never had a full excavate: perform a full excavate.
6. All poles that have been gas-treated or salt-treated shall be fully excavated, sounded, bored, and treated.
7. Pine poles shall be fully excavated, sounded, bored, and treated.
8. For all poles, fully excavate if external decay is found at the groundline, then sound, bore, and apply treatment per Section 7. Internal decay does not require a full excavate. For internal decay, apply treatment per Section 7.4.

5.2.2 Distribution PolesCalifornia - poles will be intrusively tested and the hole sterilized, unless decay is found during excavation in which case the pole will be treated if not rejected. As a general rule, any inspection hole that is drilled shall be sterilized.

1. Poles 20 years old or newer are to be inspected and sounded only. No excavation, boring, or treatment is required. For California and Oregon, poles will have an intrusive test at the next pole inspection test and treat cycle if they are four years or newer in California, and ten year or newer in Oregon.
2. Through-bore poles shall be inspected and sounded. In Oregon, through-bore poles shall receive a single bore above the through-bore area..
3. Non-through-bore poles set in concrete/asphalt shall be inspected, sounded, and bored from above to below groundline.
4. Douglas fir, larch, western red cedar, and pine poles shall be inspected and sounded, and bored. Boring applies to Oregon and California
5. West of the Cascade Mountains, Douglas-fir and Larch poles shall be inspected, sounded, bored, and treated. East of the Cascades, they shall be inspected, partially excavated, then sounded and bored.
6. In Oregon and California, salt or gas treated poles shall be partially excavated, sounded, bored, and treated. Boring applies in California. Boring and treatment applies in Oregon.
7. If internal or external decay is found at or below groundline, perform a pull-back of the soil and bore below groundline.
8. Preventive treatment to distribution poles should only be applied under the direction of asset management. Otherwise, poles should only be sounded. If sounding indicates that internal decay is present, one bore (inspection hole) should be drilled to evaluate the pole condition in accordance with Section 6.

5.3 Pole Excavation

The effectiveness of the sound and bore inspection is greatly increased when excavation is added to the process. Excavation exposes the most susceptible section of the pole for inspection.

5.3.1 Partial Excavation

1. Excavate exposing the pole for a 12-inch wide, 18-inch deep area. The diameter of this excavation shall be sufficient to permit at least a 4-inch workspace at 18 inches below groundline.
2. Measure and record the pole circumference at groundline.
3. If decay is found, perform a full excavate. Remove exposed decay from the pole exterior from its lowest point to 2 inches above the groundline using a specialized shaving tool (not a shovel), taking care that no sound wood is removed. All loose wood chips and decayed matter shall be removed from the excavation prior to backfilling.

5.3.2 Full Excavation

1. Excavate around the entire circumference of the pole to a depth of 18 inches, with a diameter sufficient to allow at least a 4-inch workspace at 18 inches below groundline.
2. Measure and record the pole circumference at the groundline.
3. Remove exposed decay from the pole exterior from its lowest point to 2 inches above the groundline using a specialized shaving tool (not a shovel), taking care that no sound wood is removed. All loose wood chips and decayed matter shall be removed from the excavation prior to backfilling.

6 Pole Evaluation

All poles owned by PacifiCorp shall be evaluated using the methods described below to determine strength and serviceability. All information obtained during this evaluation shall be recorded.

6.1 Pole Shell Thickness

If inspection holes determine that the pole has internal decay, then the procedures in this section shall be followed.

6.1.1 Shell Thickness Measurement

Pole shell thickness shall be measured using a metal shell gauge approved by PacifiCorp. The gauge shall be calibrated in inches for measuring both horizontally drilled inspection holes and inclined treated holes.

6.1.2 Shell Thickness Deductions

6.1.2.1 Fir and Pine

For fir and pine poles the inspector shall deduct ½ inch from the measured shell thickness to allow for the effects of incipient decay.

Any decayed wood should be scraped clear, and care should be taken to ensure that only sound wood is being measured.

6.1.2.2 Cedar

For cedar poles there is no deduction since cedar typically has an abrupt, well-defined transition from sound wood to decayed wood. Any decayed wood should be scraped clear, after which the gauge reading can be recorded directly with no adjustments.

6.2 Pole Strength Analysis

6.2.1 Reduced Circumference

Reduced circumference poles are those with exterior decay sufficient to potentially jeopardize structural integrity. These poles with external shell rot shall have the exterior decay removed from the pole surface at or below the groundline and the resulting pole circumference will be compared to the pole's original circumference as referenced in Table 3.

The strength of a pole containing random pockets of external and/or internal decay will be further determined using Tables 1, 2, and 3, as follows:

6.2.1.1 External Decay Pockets

After an external decay pocket is measured, the pole circumference deduction can be obtained from Table 1. Poles with external decay pockets larger than those shown in Table 1 shall be classified as Priority A, Reject/Replace. That value is subtracted from the original pole circumference as measured where the pocket was found. If there is no internal decay, Table 3 is then used directly to compare original versus current circumference and will be classified according to Section 6.2.1.3 below.

6.2.1.2 Internal Decay Pockets

If a pole has an internal decay pocket, the size of the pocket shall be measured, and the pole circumference deduction is then obtained from Table 2 (If the pocket is larger than those listed in Table 2, then proceed to Section 6.2.2, Hollow Heart Poles). The appropriate value in Table 2 is subtracted from the pole circumference. If a pole has both internal and external decay, the values from both Table 1 and Table 2 shall be subtracted from the pole's original circumference. Table 3 is then used to compare original versus current circumference and the pole then is classified according to Section 6.2.1.3 below.

Table 1—Reduced Pole Circumference for External Decay Pockets

	Circumference Deduction for External Decay Pockets (all figures in inches)							
	Pocket Width							
Pocket Depth	1	2	3	4	5	6	7	8
1	1	1	2	2	3	3	4	5
2	1	2	3	4	5	6	7	8
3	1	2	4	5	6	8	9	11
4	2	3	4	5	7	9	10	13
5	2	3	4	6	7	9	11	-

Any pole with an external decay pocket larger than those shown in Table 1 shall have its deduction calculated by addressing the pocket as if it were two smaller pockets and adding them together. For example, a 3-inch deep by 12-inch wide pocket would be addressed as though it were two 3-inch deep by 6-inch wide pockets.

Table 2—Reduced Pole Circumference for Internal Decay Pockets

Pole Circumference	Shell Thickness at Pocket Side	Depth of Internal Pocket: (all figures in inches)		
		3-Inch Deep	4-Inch Deep	5-Inch Deep
22 – 30	1	2	2	3
	2	-	1	1
	3	-	-	-
30 – 38	1	2	3	3
	2	1	1	2
	3	1	1	1
38 – 50	1	2	3	4
	2	1	2	2
	3	1	1	1

Poles with internal decay pockets larger than those shown in Table 2 shall be treated as Hollow Heart Poles, Section 6.2.2. Poles with remaining shell thickness of 1 inch or less will be a Priority A Reject/Replace.

Poles must have a shell thickness of at least one inch to be reinforceable in accordance with Policy 014 and Standard EB 141, Poles, Reinforcing.

Table 3—Minimum Pole Circumference (all figures in inches)

Original Circumf.	Priority B Reject Circumf.	Priority A Replace Circumf.	Original Circumf.	Priority B Reject Circumf.	Priority A Replace Circumf.
25.0	22.0	17.3	58.0	51.0	40.1
26.0	22.9	18.0	59.0	51.9	40.8
27.0	23.8	18.7	60.0	52.8	41.5
28.0	24.6	19.3	61.0	53.7	42.2
29.0	25.5	20.0	62.0	54.6	42.8
30.0	26.4	20.7	63.0	55.4	43.5
31.0	27.3	21.4	64.0	56.3	44.2
32.0	28.2	22.1	65.0	57.2	44.9
33.0	29.0	22.8	66.0	58.1	45.6
34.0	29.9	23.5	67.0	59.0	46.3
35.0	30.8	24.2	68.0	59.8	47.0
36.0	31.7	24.9	69.0	60.7	47.7
37.0	32.6	25.6	70.0	61.6	48.4
38.0	33.4	26.3	71.0	62.5	49.1
39.0	34.3	27.0	72.0	63.4	49.8
40.0	35.2	27.6	73.0	64.2	50.4
41.0	36.1	28.3	74.0	65.1	51.1
42.0	37.0	29.0	75.0	66.0	51.8
43.0	37.8	29.7	76.0	66.9	52.5
44.0	38.7	30.4	77.0	67.8	53.2
45.0	39.6	31.1	78.0	68.6	53.9
46.0	40.5	31.8	79.0	69.5	54.6
47.0	41.4	32.5	80.0	70.4	55.3
48.0	42.2	33.2	81.0	71.3	56.0
49.0	43.1	33.9	82.0	72.2	56.7
50.0	44.0	34.6	83.0	73.0	57.4
51.0	44.9	35.2	84.0	73.9	58.0
52.0	45.8	35.9	85.0	74.8	58.7
53.0	46.6	36.6	86.0	75.7	59.4
54.0	47.5	37.3	87.0	76.6	60.1
55.0	48.4	38.0	88.0	77.4	60.8
56.0	49.3	38.7	89.0	78.3	61.5
57.0	50.2	39.4	90.0	79.2	62.2

6.2.1.3 Reduced-Circumference Pole Classification

Poles falling below the "Reject Circumference" value but above the "Replace Circumference" value in Table 3 will be classified as Priority B, Reject/Reinforceable poles.

Most poles falling below the "Replace Circumference" value in Table 3 will be classified as Priority A, Reject/Replace. However, in some cases, such as when the decay is at or near groundline, or with fire damage, a pole may be classified as Priority A, Reject/Reinforceable per PacifiCorp Policy 014, *Wood Pole Reinforcing Using Steel Reinforcers Transmission and Distribution Lines*, but the reinforcement work must be completed within the Priority A timeframe.

Poles must have a shell thickness of at least one inch to be reinforceable in accordance with PacifiCorp Policy 014, *Wood Pole Reinforcing Using Steel Reinforcers Transmission and Distribution Lines* and standard EB 141, *Poles, Reinforcing*.

The "Reject Circumference" column in Table 3 gives the minimum pole circumference (88% of original) required to maintain 67% pole strength. The "Replace Circumference" column gives the minimum pole circumference (69% of original) required to maintain 33% pole strength.

6.2.2 Hollow Heart Poles

Hollow heart poles are those with significantly decayed or void centers but may have sound shell wood. For internal voids greater than shown in Table 2 (5 inches or deeper), evaluate the pole as follows:

Transmission Poles: Remaining shell thickness of 2 inches or less will be a Priority A Reject/Replace; 2-3 inches will be a Priority B Reject/Replace; shell thickness greater than 3 inches and meeting the Satisfactory strength requirement per Table 3 shall receive internal void treatment per Section 7.4.

Distribution Poles: Remaining shell thickness of 1 inch or less will be a Priority A Reject/Replace; 1-2 inches will be a Priority B Reject/Replace.

For fir and pine poles the inspector shall deduct ½ inch from the measured shell thickness to allow for the effects of incipient decay.

7 Treatment Preservatives

Treatments shall be applied on poles that pass inspection and evaluation tests and qualify as being either Sound or Reinforceable, and that have not been treated within the last 5 years. Poles not owned by PacifiCorp are not to receive treatments under this program; document foreign-owned poles that have been treated by others within the past 5 years.

The Environmental Protection Agency must approve all chemical treatments used on wood poles. All manufacturer labels and safety data sheets shall be strictly followed.

The PacifiCorp authorized preservative treatment supplier is Genics™. Only the authorized preservatives supplied by Genics™ should be used. The use of any other preservative treatments must be pre-approved by PacifiCorp. Table 4 shows the approved preservatives.

Table 4—Authorized Preservatives

Product	Type	Ingredients
Cobra™ Rod	Internal Preservative (Solid Rod)	Anhydrous disodium octaborate tetrahydrate, copper (from copper hydroxide), boric acid
Genics™ CuB	Internal Preservative (Liquid)	Disodium octaborate tetrahydrate, boric acid, copper hydroxide
Cobra™ Wrap	External Preservative	Copper naphenate, hydrocarbon solvent
Genics™ CuB 20 Paste and Kraft/ Poly Paper	External Preservative (Alternate)	Copper-borate CuB 20 paste. Apply by brush and cover with kraft/poly paper.

Below are general guidelines for installing Genics™ preservatives. The information provided below is either a direct quote or paraphrased from material and documents provided by Genics™. Inspectors and individuals providing pole treatment should follow all manufacturer's recommendations and safety precautions.

The amount of treatment to be applied is provided in EBU-PL-S03, *Supplemental Wood Pole Test and Treatment – Distribution and Transmission Poles.* Refer to manufacture's pole loading diagrams for drill patterns.

7.1 Internal Preventive Treatment

Serviceable poles are to be internally treated for protection against fungal decay and insects and to interrupt degradation. Serviceable and reinforced poles and all non-decayed wood stubs shall also be treated. Decayed wood stubs on serviceable poles shall be replaced.

For preventive treatment, Cobra™ Rods (diffusible rods comprised of copper and boron) shall be used on all poles requiring treatment. Cobra™ Rods are placed into treatment holes as described below:

1. Measure the pole circumference at the groundline.
2. Determine the number and depth of the holes for preservative treatment to be used as indicated in EBU-PL-S03 (Table 6 or 7).
3. Drill ½" treatment holes at a 45-degree angle following manufacturer's recommendation for drill pattern (refer to Genics™ pole load diagrams).
4. Apply Genics™ CuB to holes starting from the bottom hole to the top hole.
5. Insert Cobra™ Rods in accordance with EBU-PL-S03 (Table 6 or 7).
6. Plug the bore holes with 9/16" Cobra™ Plug.

7.2 Internal Preventive Treatment for Poles Previously Treated with MITC

PacifiCorp poles were treated with methyl-isothiocyanate (MITC) fume in the past. The following guidelines should be followed to install Cobra™ Rods on poles previously treated with MITC fume:

1. If the pole is not in need of replacement or can be reinforced, drill out the existing wood dowel or remove plastic plug from previous installation of MITC fume. Be careful to not drill too deeply, so as not to drill into the MITC vial.
2. Remove the MITC fume vials from the hole and dispose in accordance with manufacturer recommendations and local regulations.
3. Use EBU-PL-S03 (Table 8) to determine the number of rods and ounces of liquid preservative to be applied.
4. Apply liquid preservative (Genics™ CuB) to holes starting from the bottom hole moving to the top hole.
5. Insert Cobra™ Rods into the borings as per EBU-PL-S03 (Table 8) starting from the bottom hole moving towards the top hole.
6. Push the rods to the bottom of the hole and add more additive as needed to fill the hole, but do not exceed the maximum recommended amount.
7. Plug all holes with 15/16" Cobra™ Plugs.

7.3 External Pole Treatment

Poles that have been excavated and meet evaluation requirements as serviceable shall have their external surfaces treated using Cobra™ Wrap or Genics CuB 20 Paste.

Cobra™ Wrap is a copper naphthenate bandaging system. It comes pre-packaged with preservatives and requires no additional chemicals to be applied. The following guidelines should be used for installing Cobra™ Wraps:

1. Fully excavate around the poles in accordance with Section 5.3.
2. Excess dirt and decayed wood should be removed from sound wood with a wire brush or pole shaving tool (do not use shovels, axes, or hatches).
3. Measure the circumference of the pole and determine the amount of bandage required per EBU-PL-S03 (Table 10).
4. Lay out the required number of sections and expose the copper naphthene solution pad by cutting diagonal slits every 1-½ inches in the inner plastic when using the Cobra Wrap SD. (If using the Cobra Wrap standard peel the backing off to expose the copper naphthene solution.) On the overlap portion, leave a sufficient tail attached to the outermost edge forcing preservative to move back into wood zone for penetration.
5. Wrap proper length Cobra™ Wrap around the pole with saturated pad against the pole and staple or tack firmly in place. Staple short side of the backing first and overwrap with longer edge. Allow wrap to extend 2 inches above groundline.
6. After complete inspection and installation of the protective wrap, the excavation shall be backfilled and compacted by tamping firm every 6 to 8 inches. The

backfill should mound up the pole to allow for future setting and drainage away from the pole. Care must be exercised to avoid damaging the wrapping during backfilling. All landscaping shall be replaced in good condition. All ground wires, straps and ground rods disturbed during inspection or treatment shall be reinstalled to acceptable condition by a qualified electrical worker.

Alternatively, to the Cobra™ Wraps, the Genics CuB 20 paste may be used. Follow steps 1-3 above, then apply the CuB 20 paste by brush in accordance with manufacturer's recommendation and wrap using kraft / poly paper. Firmly secure the paper wrap against the pole and staple or tack in place. Allow wrap to extend 2 inches above groundline. After complete inspection and installation of the paste and wrap, complete the backfill per step 6 above.

7.4 Internal Void Treatment

Poles with internal voids that still have acceptable strength or that can be reinforced shall be filled with Genics™ CuB, a preservative solution containing copper hydroxide and disodium octaborate tetrahydrate. All internal voids and inspection holes shall be treated in accordance with this section.

The Genics™ CuB solution shall be mixed with a foaming agent in accordance with manufacturer recommendations and be applied with a pressurized garden sprayer. The treatment shall be applied through the lowest inspection hole and forced upward filling the entire void as follows:

1. Either use the treatment holes or drill a ½-inch hole into the vertical center of the void at a 45-degree angle downward from the horizon.
2. Drill inspection holes at increments of approximately six inches until solid wood is reached. Keep the holes clean of sawdust.
3. Avoid checks. If a hole intersects a check, plug the hole and drill another. Drill from side to side that will not allow for intersection with a check.
4. Using a sprayer, flood the void with foaming Genics™ CuB. If the preservative is escaping through a check or crack, plug the hole and apply foam to a drill hole which does not intersect a check or crack.
5. Starting from the bottom hole, apply the foaming Genics™ CuB until the foam escapes from the hole above it. Stop and plug the original hole. Then apply in the hole immediately above until the foam comes out of the hole above it. Continue this process until all holes and the void are filled.
6. Occasionally shake canister well, especially between poles, to ensure the foaming agent and preservative stay mixed. Try to divide the chemical equally between holes.
7. Apply Genics™ CuB foam solution to any exposed check and inspection holes.
8. Plug the bore holes with 7/16-inch, boron treated, plastic Cobra™ Plugs.

8 Soil Sterilization – Oregon

When so directed by a designated PacifiCorp representative, the soil shall be sterilized completely within a 6-foot radius of the pole using an EPA-approved sterilant. Follow manufacturer's instructions for safety, procedure and application amounts. Care shall be

taken to prevent sterilant from entering streams or any gulch leading thereto. Do not use sterilant in any area where trees or desirable plants could be adversely affected. Sterilant shall be spread uniformly over the area to be treated, and caution shall be exercised to stay within the boundaries of the area to be treated. Application personnel shall comply with all federal, state, local and PacifiCorp regulations and policies concerning the application of sterilant.

9 Pole Tagging

Pole tags shall be installed in accordance with PacifiCorp Standard EB 461, *Tag, Fumigated, Pole*. All tags shall be held in place with aluminum or galvanized nails.

9.1 Reject/Replace Pole Tags

Poles evaluated as Reject/Replace Priority A shall be tagged with two plain white aluminum tags, SI# 6156251.

Poles evaluated as Reject Priority B shall be tagged with one plain white aluminum tag, SI# 6156251.

9.2 Reject/Reinforceable Pole Tags

Priority A poles evaluated as Reject/Reinforceable shall be tagged with two yellow aluminum tags, SI# 6156252.

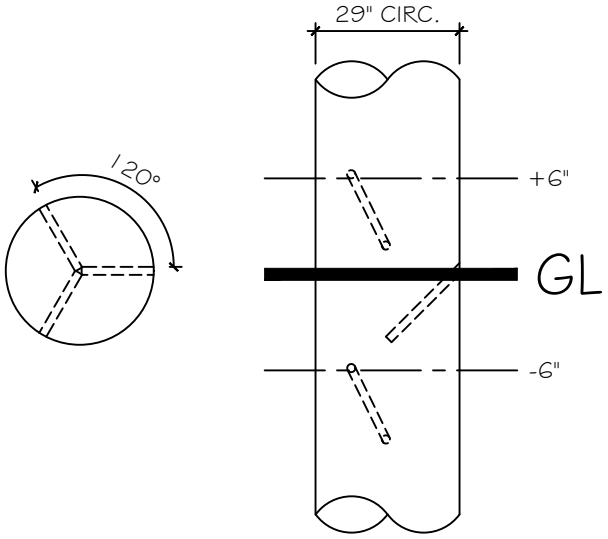
Priority B poles evaluated as Reject/Reinforceable shall be tagged with one yellow aluminum tag, SI# 6156252.

9.3 Pole Treatment Tags

All treated poles shall be tagged to indicate the year and type of treatment applied. Tag the pole at eye level to indicate treatment and date (year). Keep records of all poles including the location, date, number of borings, type of treatment, and number of rods installed.

END

Reference Example: 29" Pole

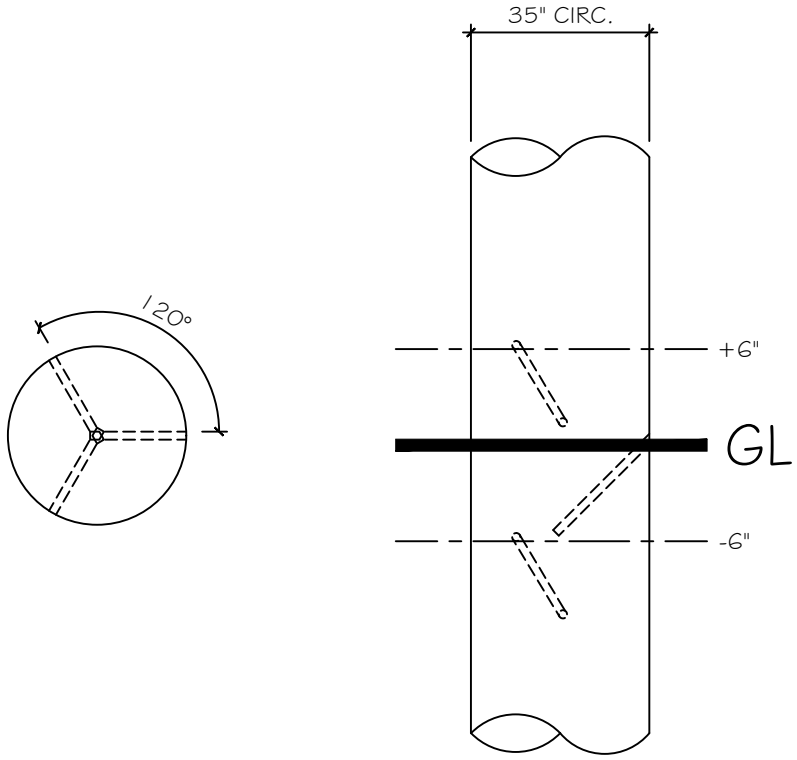


Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	10	1/2"	0	0.92
Groundline	10	1/2"	0	0.92
6" Below GL	10	1/2"	1	0.48

SCALE: 1" = 1' 0"

genics Wherever Wood Is Used™	JOB # POLE BORING PATTERN	NOTES	PAGE 1
	CUSTOMER(S):		OF 9
	MODEL:	DATE: Jan. 26, 22	

Reference Example: 35" Pole

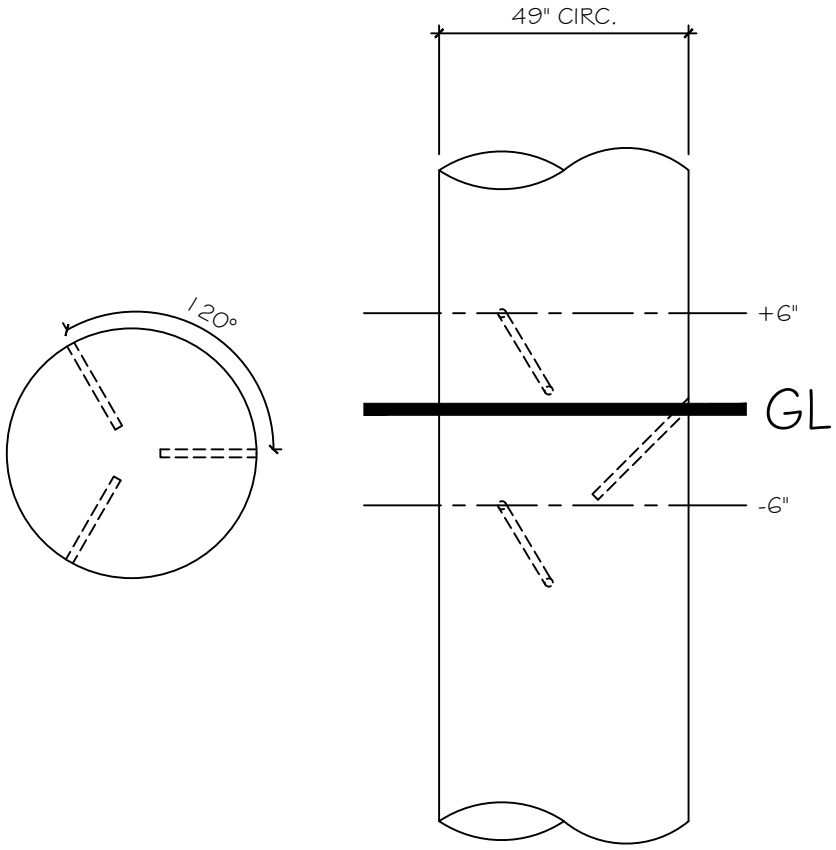


Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	10	1/2"	0	0.92
Groundline	10	1/2"	1	0.48
6" Below GL	10	1/2"	1	0.48

SCALE: 1" = 1' 0"

genics Wherever Wood Is Used™	JOB # POLE BORING PATTERN	NOTES	PAGE 2
	CUSTOMER(S):		OF 9
	MODEL:	DATE: Jan. 26, 22	

Reference Example: 49" Pole



Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	15	1/2"	0	1.47
Groundline	15	1/2"	2	0.6
6" Below GL	15	1/2"	2	0.6

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

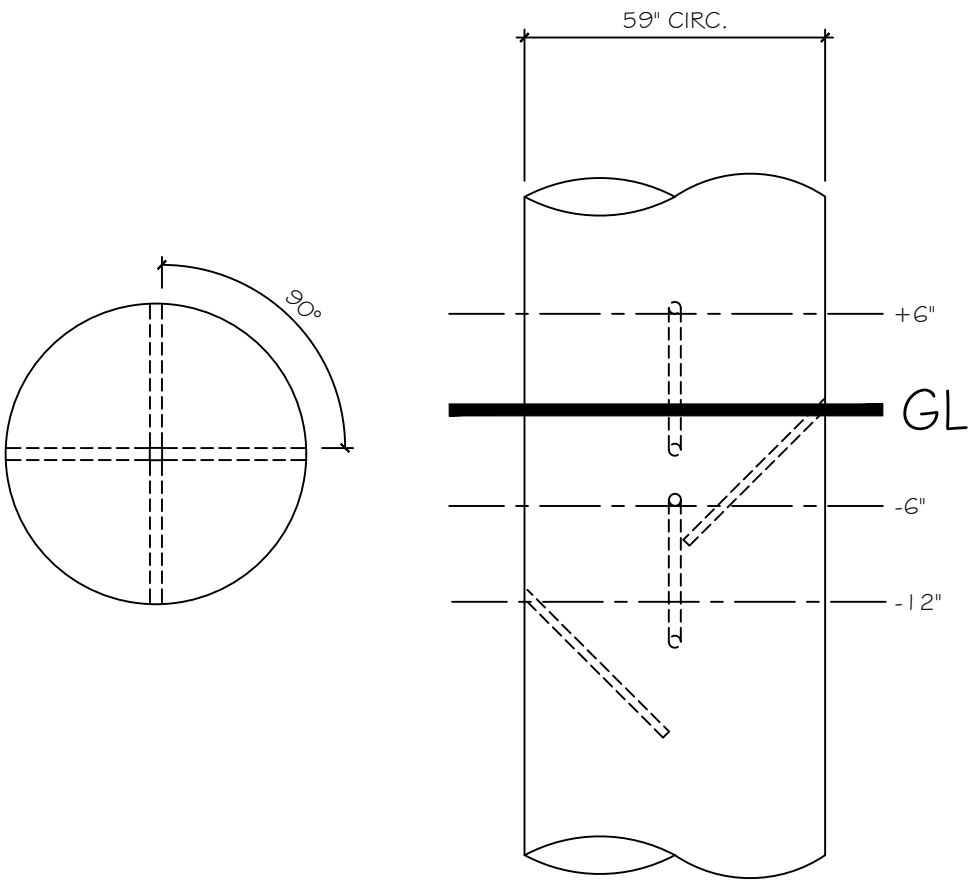
CUSTOMER(S):

MODEL:

NOTES

DATE: Jan. 26, 22

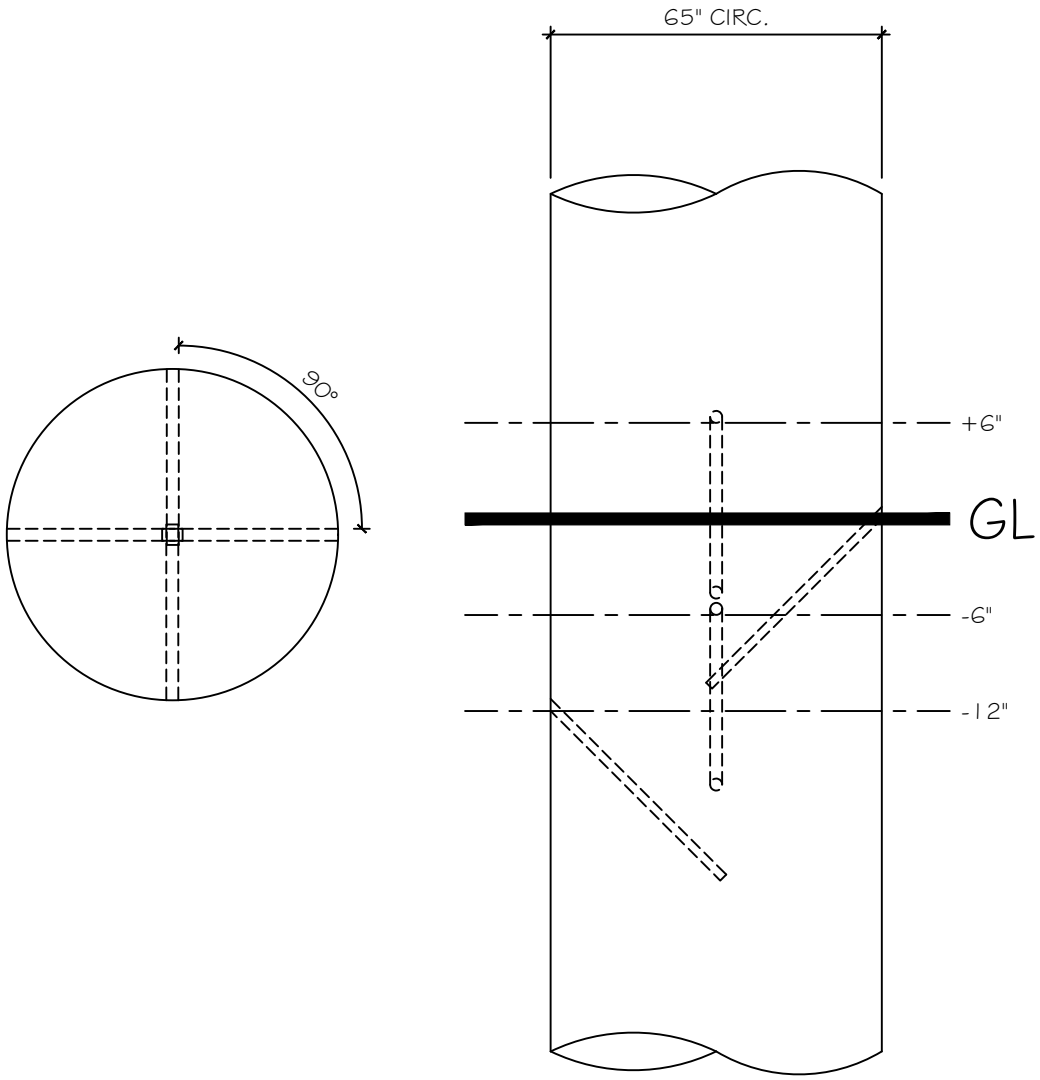
Reference Example: 59" Pole



Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	15	1/2"	0	1.47
Groundline	15	1/2"	2	0.6
6" Below GL	15	1/2"	2	0.6
12" Below GL	15	1/2"	2	0.6

SCALE: 1" = 1' 0"

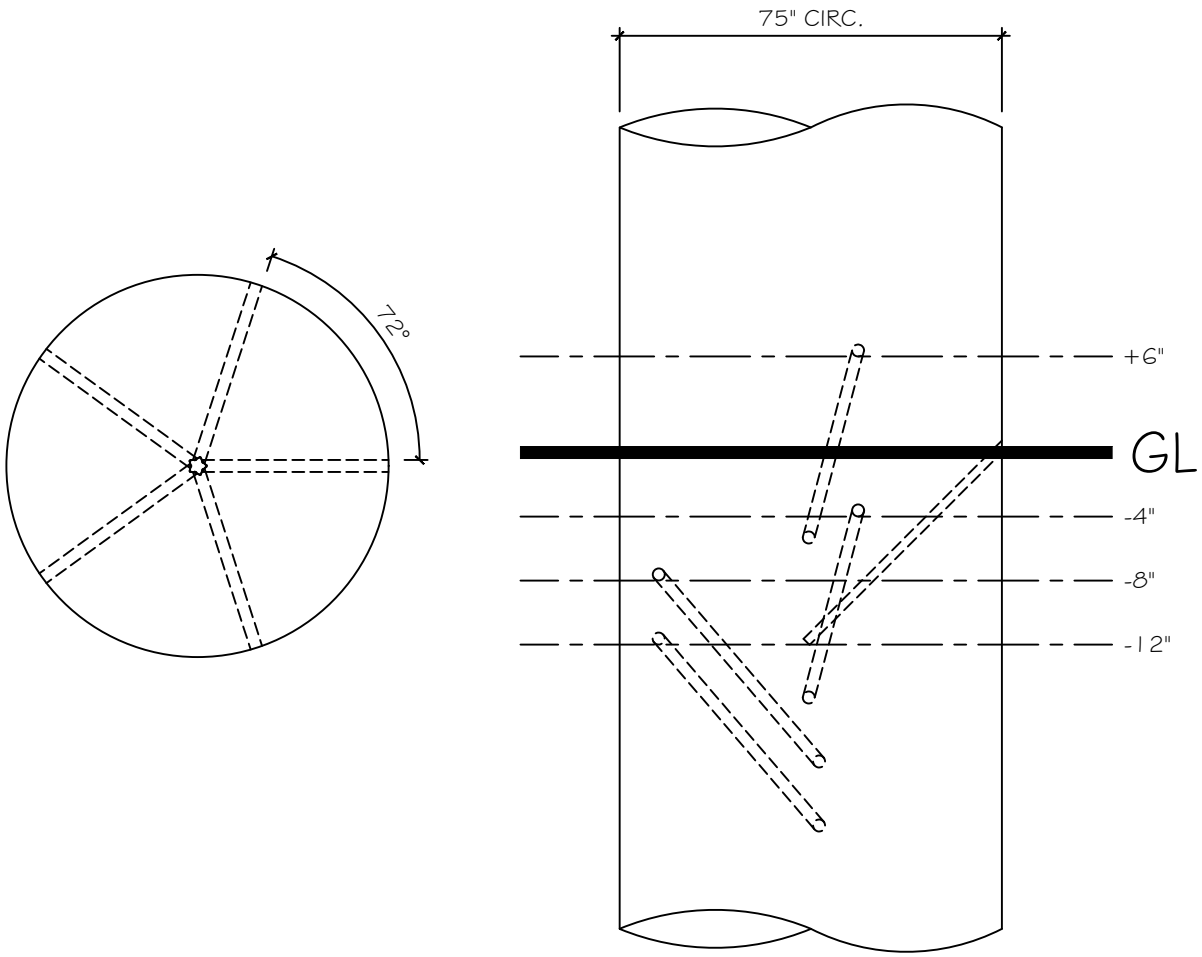
Reference Example: 65" Pole



Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	15	1/2"	1	1.03
Groundline	15	1/2"	2	0.6
6" Below GL	15	1/2"	2	0.6
12" Below GL	15	1/2"	2	0.6

SCALE: 1" = 1' 0"

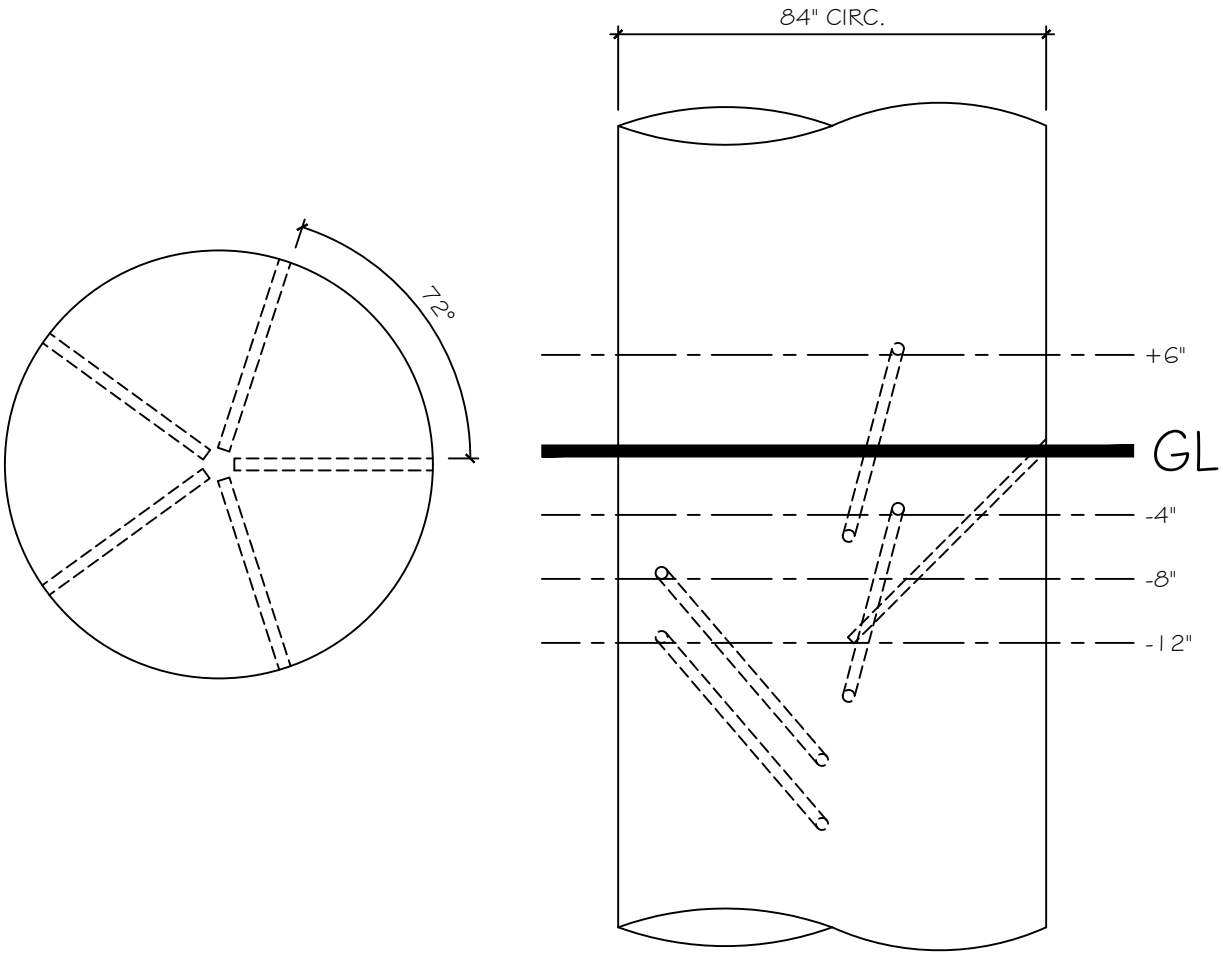
Reference Example: 75" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	16	1/2"	1	1.14
Groundline	16	1/2"	2	0.7
4" Below GL	16	1/2"	2	0.7
8" Below GL	16	1/2"	3	0.27
12" Below GL	16	1/2"	3	0.27

SCALE: 1" = 1' 0"

Reference Example: 84" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	16	1/2"	2	0.7
Groundline	16	1/2"	3	0.27
4" Below GL	16	1/2"	3	0.27
8" Below GL	16	1/2"	3	0.27
12" Below GL	16	1/2"	3	0.27

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

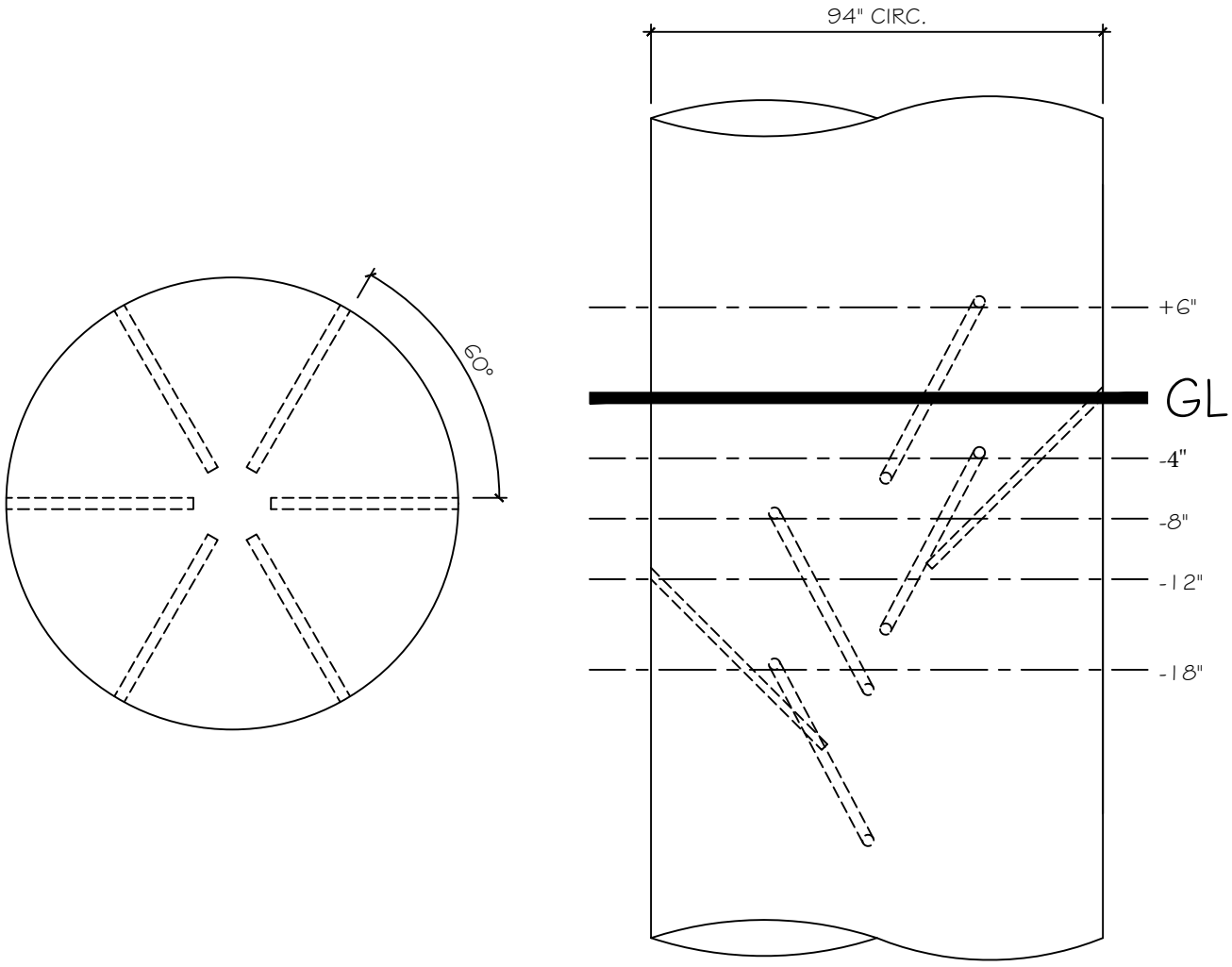
CUSTOMER(S):

MODEL:

NOTES

DATE: Jan. 26, 22

Reference Example: 94" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
6" Above GL	16	1/2"	3	0.27
Groundline	16	1/2"	3	0.27
4" Below GL	16	1/2"	3	0.27
8" Below GL	16	1/2"	3	0.27
12" Below GL	16	1/2"	3	0.27
18" Below GL	16	1/2"	3	0.27

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

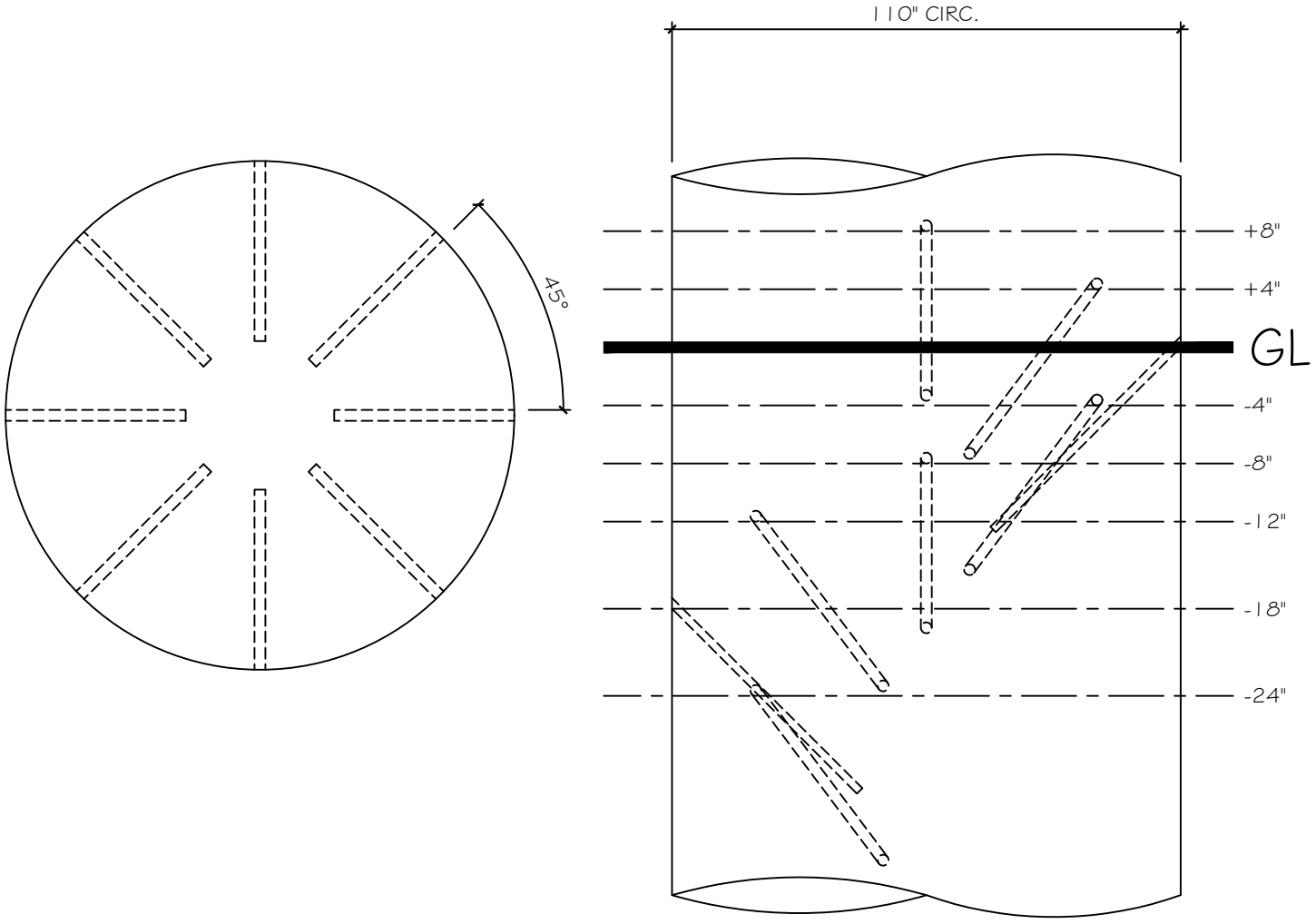
CUSTOMER(S):

MODEL:

NOTES

DATE: Jan. 26, 22

Reference Example: 110" Pole



Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 1/2" Cobra Rods	Volume of CuB (Oz)
8" Above GL	18	1/2"	1	1.35
4" Above GL	18	1/2"	2	0.91
Groundline	18	1/2"	3	0.47
4" Below GL	18	1/2"	3	0.47
8" Below GL	18	1/2"	3	0.47
12" Below GL	18	1/2"	4	0.08
18" Below GL	18	1/2"	4	0.08
24" Below GL	18	1/2"	4	0.08

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

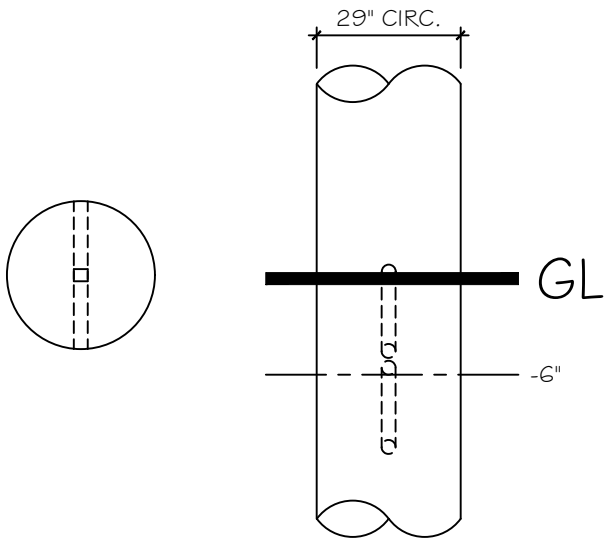
MODEL:

NOTES

DATE: Jan. 26, 22

NOTE: 7/8" BORING HOLES @ 10" LONG

Reference Example: 29" Pole



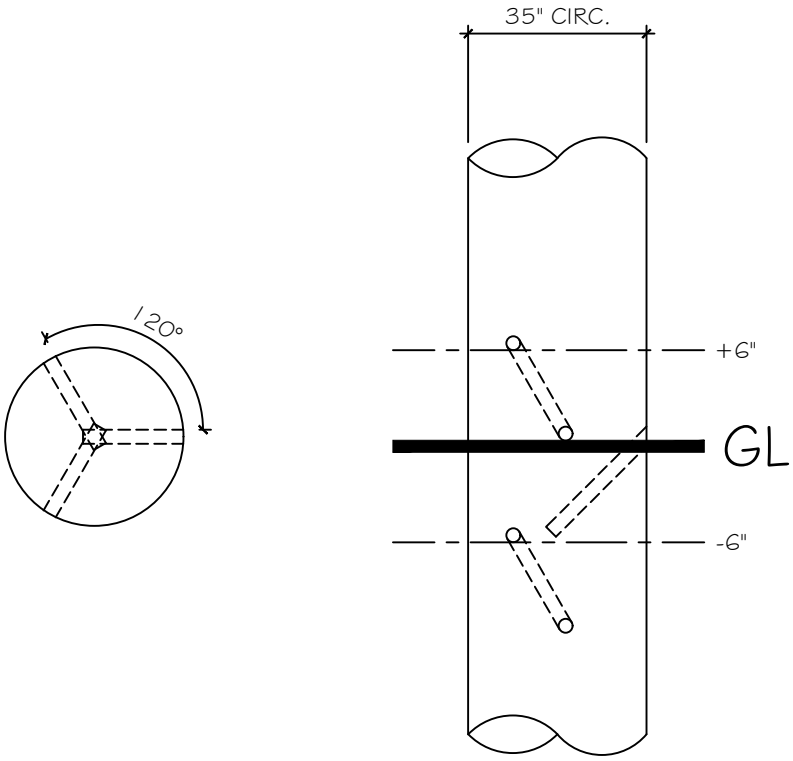
Loading Table				
	Depth	**Boring Diameter**	**Chemical Loading**	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
Groundline	10	7/8"	0	2.86
6" Below GL	10	7/8"	1	1.97

SCALE: 1" = 1' 0"

genics Wherever Wood Is Used™	JOB # POLE BORING PATTERN	NOTES	PAGE 1
	CUSTOMER(S):		OF 9
	MODEL:	DATE: Jan. 24, 22	

NOTE: 7/8" BORING HOLES @ 10" LONG

Reference Example: 35" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
6" Above GL	10	7/8"	0	2.83
Groundline	10	7/8"	1	1.97
6" Below GL	10	7/8"	1	1.97

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

MODEL:

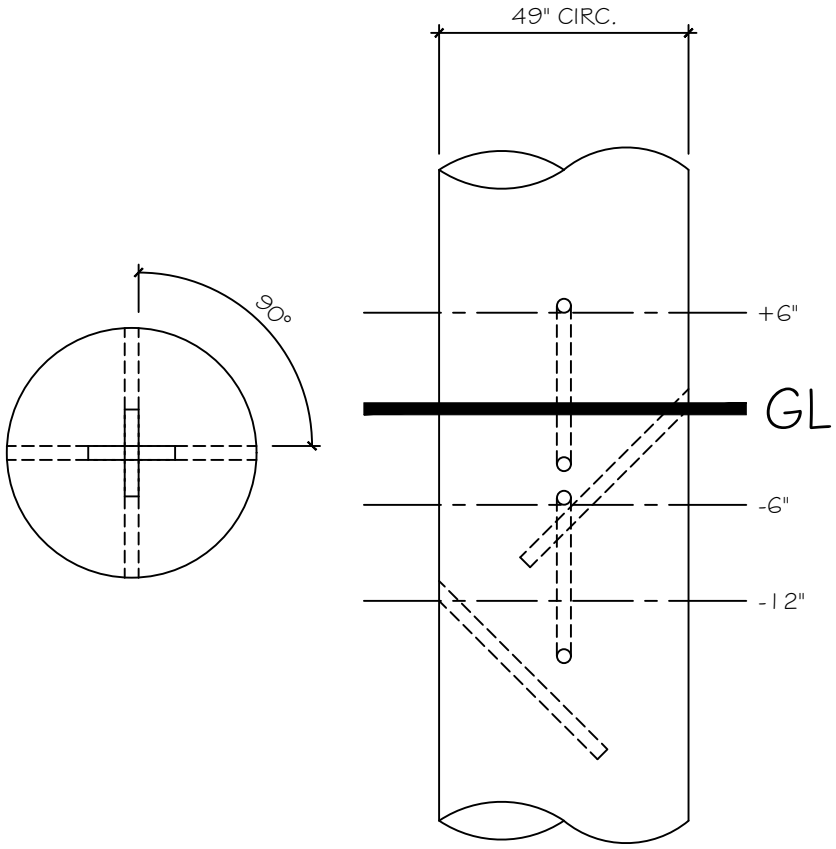
NOTES

DATE: Jan. 24, 22

PAGE 2 OF 9

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 49" Pole

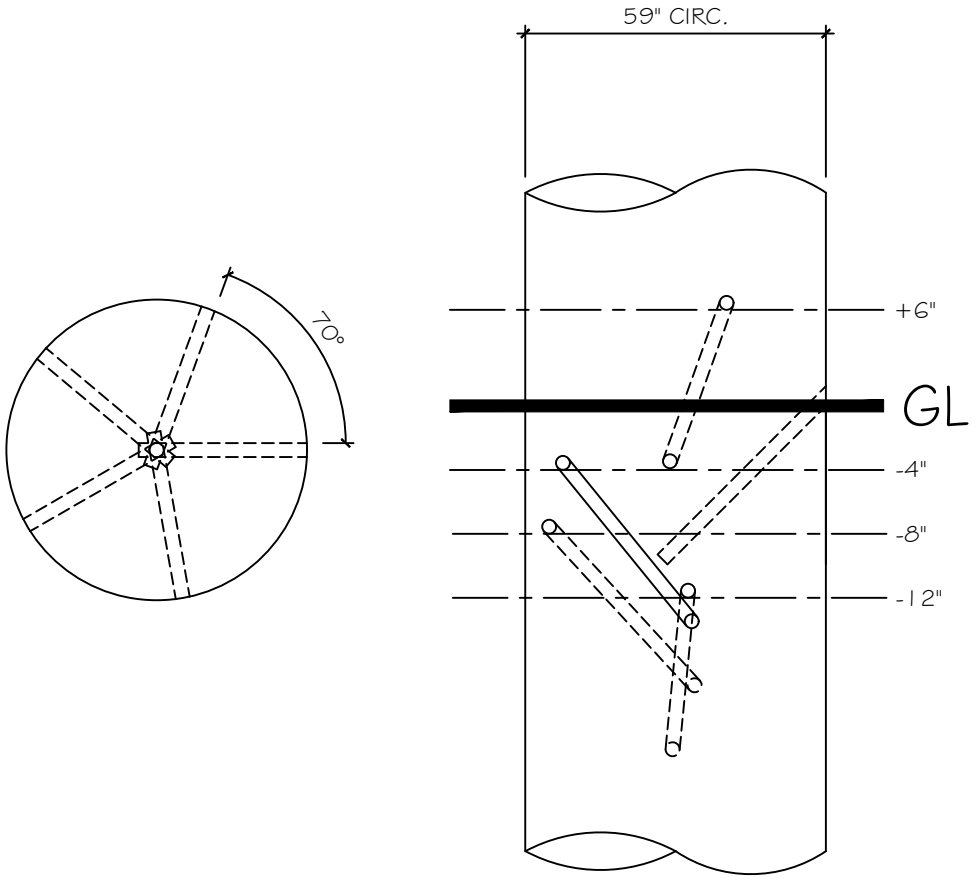


Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
6" Above GL	14	7/8"	1	3.3
Groundline	14	7/8"	1	3.3
6" Below GL	14	7/8"	1	3.3
12" Below GL	14	7/8"	1	3.3

SCALE: 1" = 1' 0"

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 59" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
6" Above GL	14	7/8"	0	4.16
Groundline	14	7/8"	1	3.3
4" Below GL	14	7/8"	1	3.3
8" Below GL	14	7/8"	2	2.44
12" Below GL	14	7/8"	2	2.44

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN
CUSTOMER(S):
MODEL:
NOTES
DATE: Jan. 24, 22
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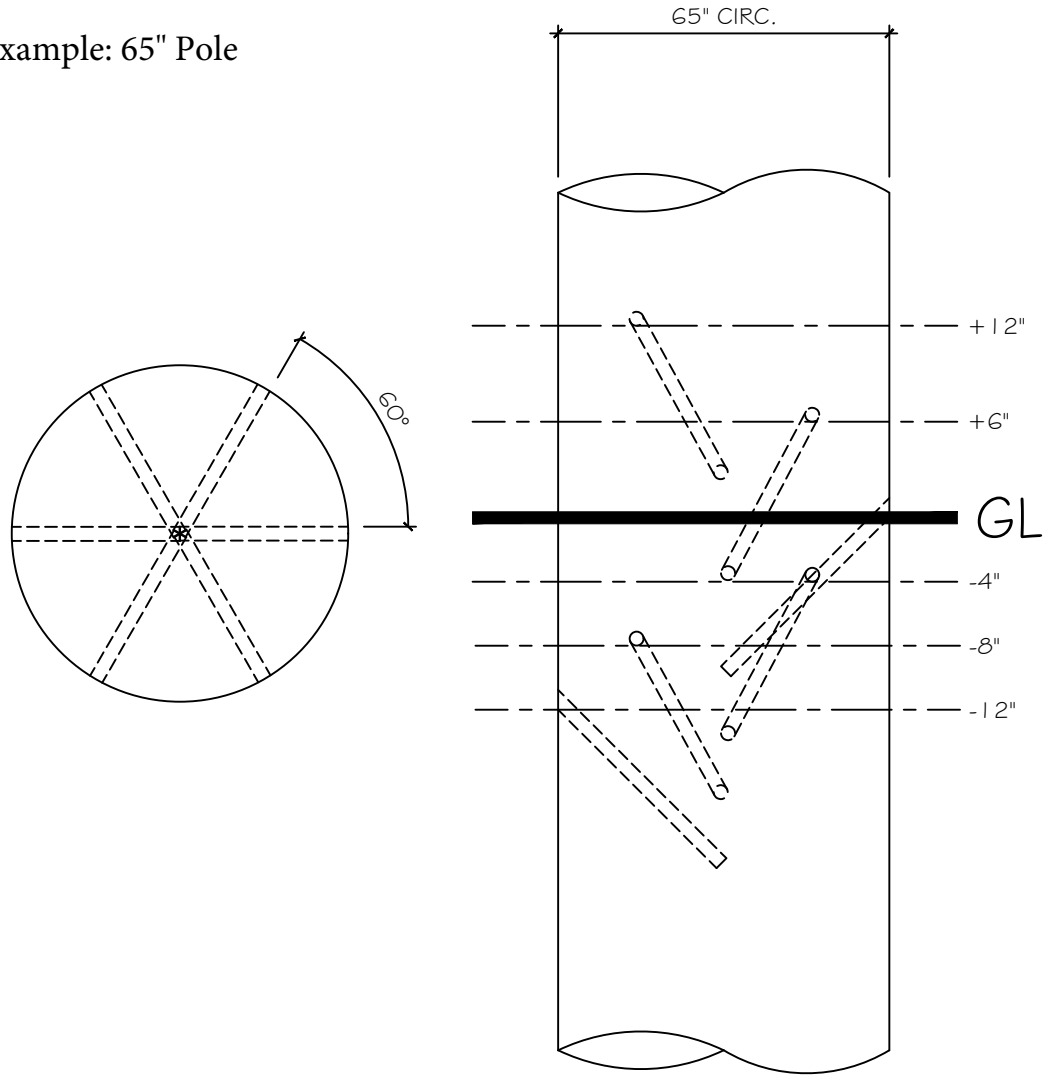
OF 9

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 65" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
12" Above GL	14	7/8"	0	4.16
6" Above GL	14	7/8"	1	3.3
Groundline	14	7/8"	1	3.3
4" Below GL	14	7/8"	1	3.3
8" Below GL	14	7/8"	2	2.44
12" Below GL	14	7/8"	2	2.44

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

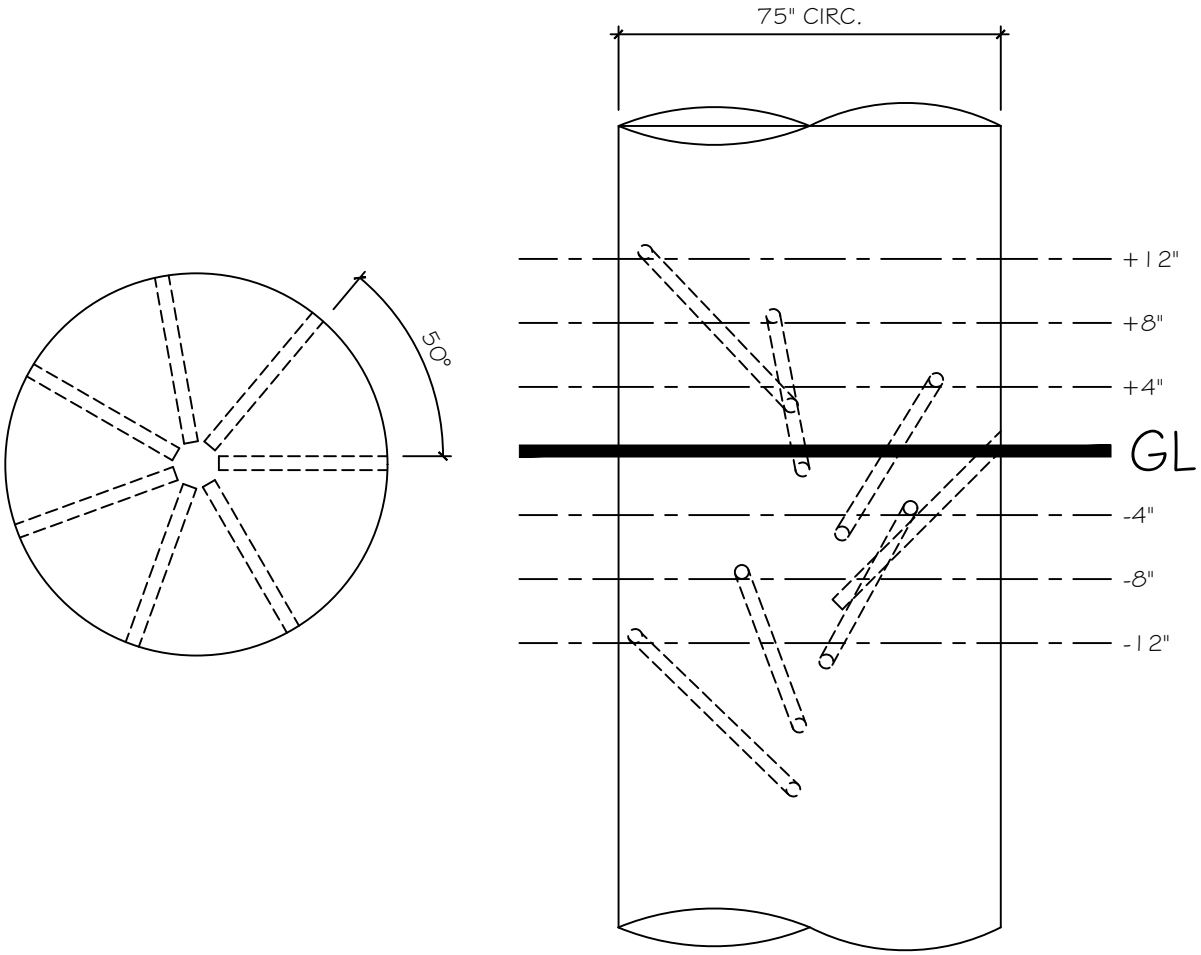
MODEL:

NOTES

DATE: Jan. 24, 22

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Pole: 75" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
12" Above GL	14	7/8"	0	4.16
8" Above GL	14	7/8"	1	3.3
4" Above GL	14	7/8"	1	3.3
Groundline	14	7/8"	2	2.44
4" Below GL	14	7/8"	2	2.44
8" Below GL	14	7/8"	2	2.44
12" Below GL	14	7/8"	3	1.58

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

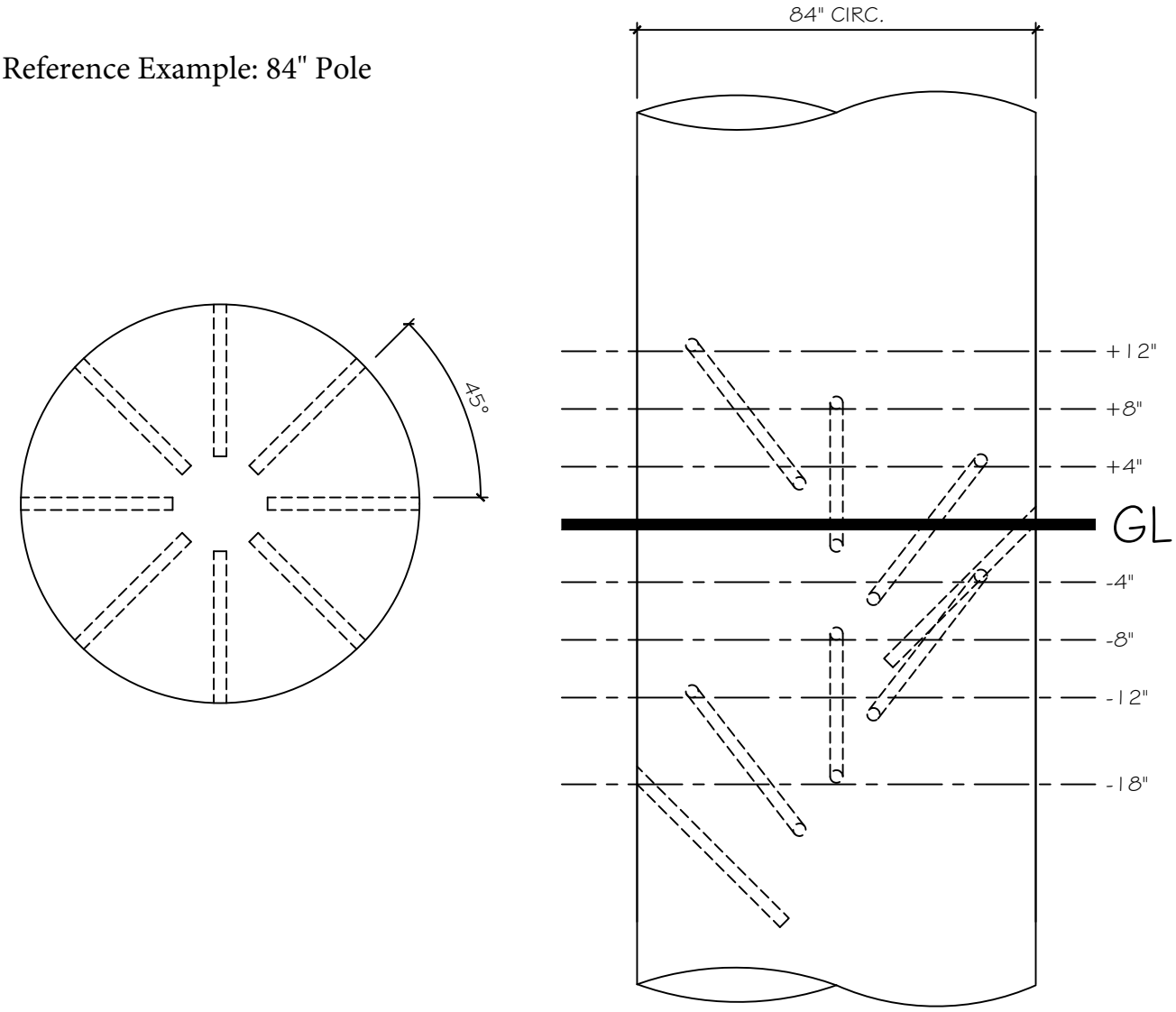
MODEL:

NOTES

DATE: Jan. 24, 22

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 84" Pole

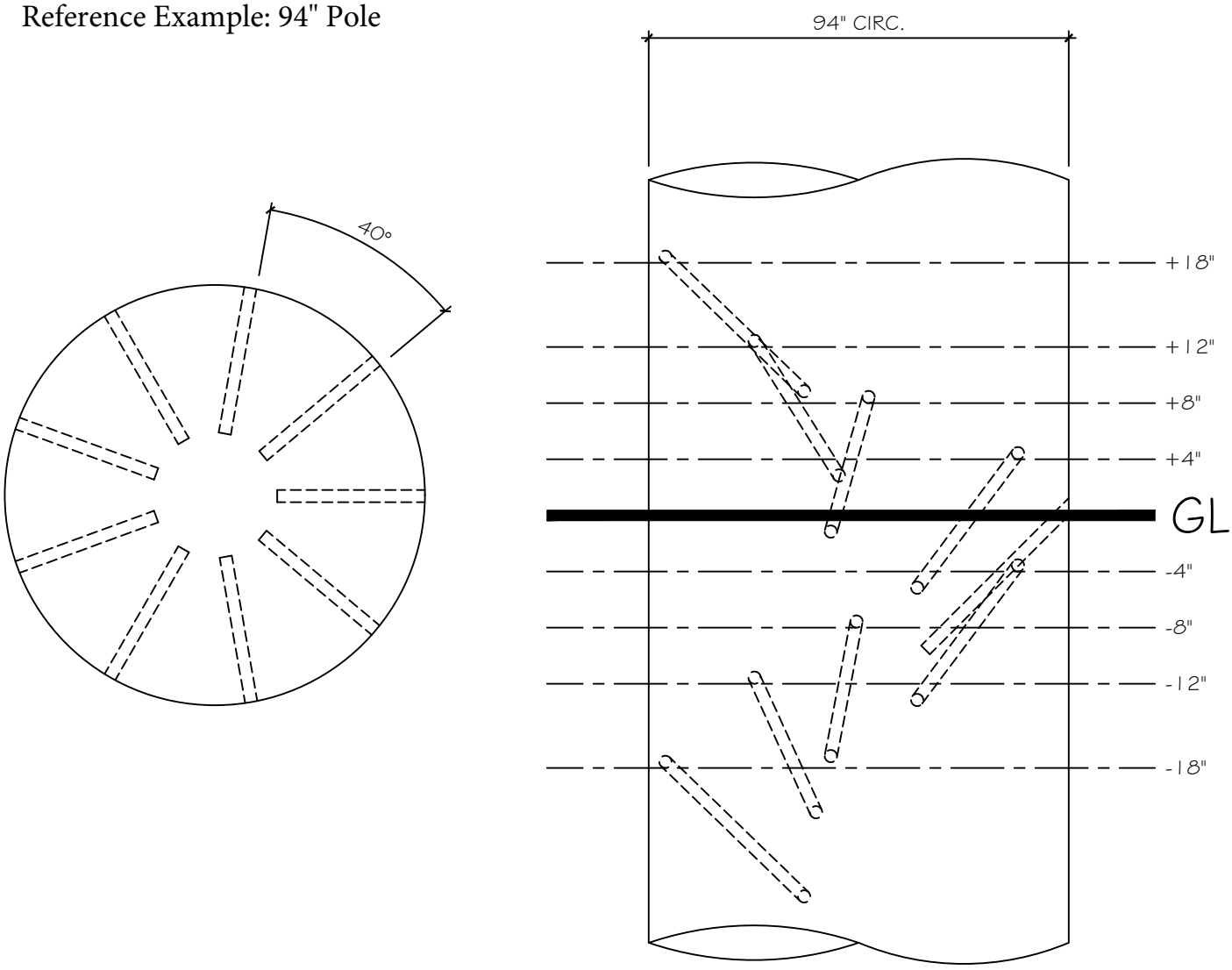


Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
12" Above GL	14	7/8"	0	4.16
8" Above GL	14	7/8"	1	3.3
4" Above GL	14	7/8"	2	2.44
Groundline	14	7/8"	3	1.58
4" Below GL	14	7/8"	3	1.58
8" Below GL	14	7/8"	3	1.58
12" Below GL	14	7/8"	3	1.58
18" Below GL	14	7/8"	3	1.58

SCALE: 1" = 1' 0"

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 94" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
18" Above GL	14	7/8"	0	4.16
12" Above GL	14	7/8"	1	3.3
8" Above GL	14	7/8"	2	2.44
4" Above GL	14	7/8"	2	2.44
Groundline	14	7/8"	3	1.58
4" Below GL	14	7/8"	3	1.58
8" Below GL	14	7/8"	3	1.58
12" Below GL	14	7/8"	3	1.58
18" Below GL	14	7/8"	3	1.58

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

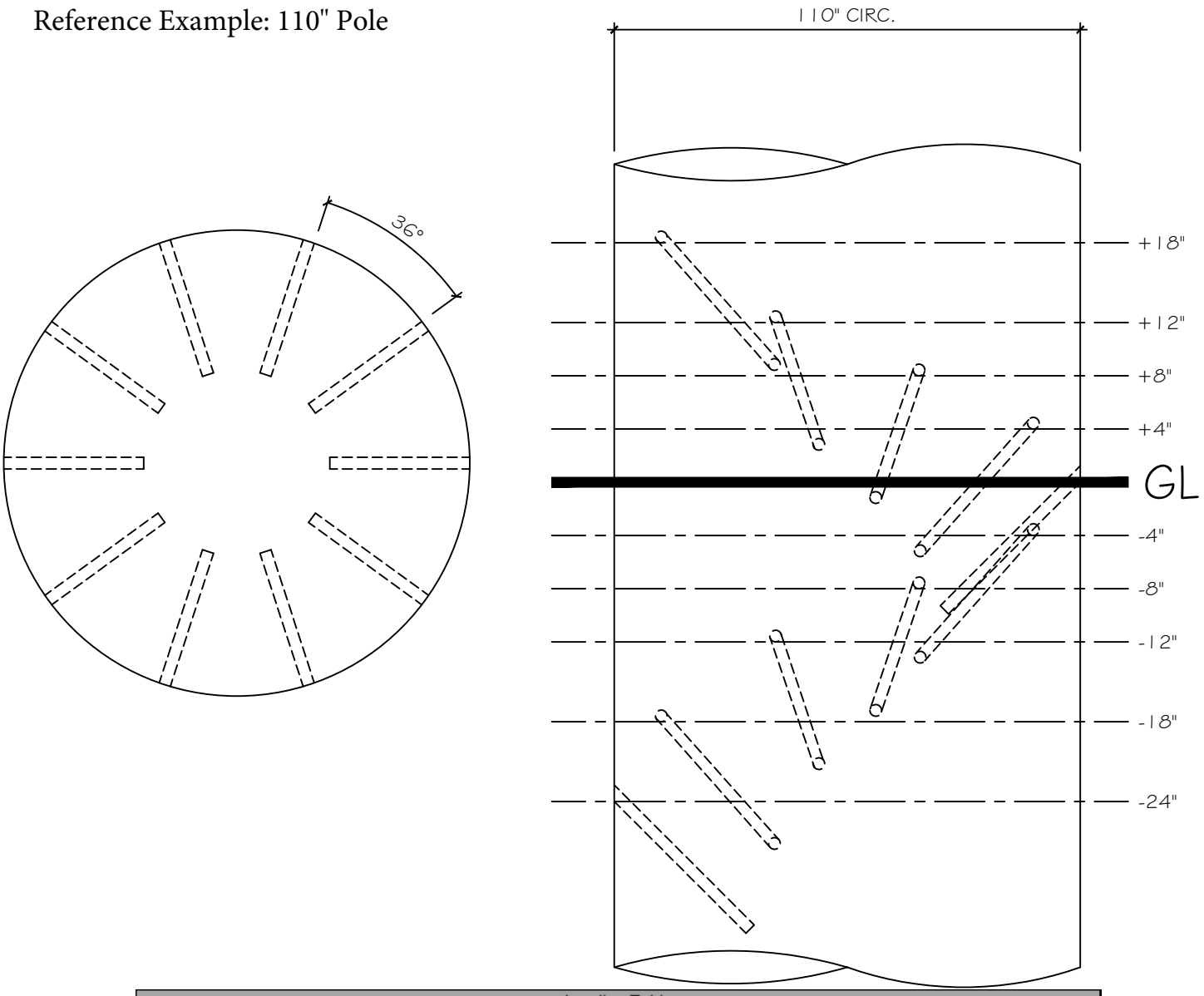
MODEL:

NOTES

DATE: Jan. 24, 22

NOTE: 7/8" BORING HOLES @ 14" LONG

Reference Example: 110" Pole



Loading Table				
	Depth	Boring Diameter	Chemical Loading	
Boring Location	Inches	Inches	# of 3/4" Cobra Rods	Volume of CuB (Oz)
18" Above GL	14	7/8"	0	4.16
12" Above GL	14	7/8"	3	1.58
8" Above GL	14	7/8"	3	1.58
4" Above GL	14	7/8"	3	1.58
Groundline	14	7/8"	3	1.58
4" Below GL	14	7/8"	3	1.58
8" Below GL	14	7/8"	3	1.58
12" Below GL	14	7/8"	3	1.58
18" Below GL	14	7/8"	3	1.58
24" Below GL	14	7/8"	3	1.58

SCALE: 1" = 1' 0"

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JOB # POLE BORING PATTERN

CUSTOMER(S):

MODEL:

NOTES

DATE: Jan. 24, 22

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Policy

SUBSTATION INSPECTION

Asset Management Policy No. 034

Author (R3):	Eddie Summit
Approval:	Alex Vaz
Authoring department:	Asset Management
Approved location:	J:\Publications\FPP\SUB\POL
File number-name:	034-Substation Inspection.docx
Revision number:	5
Revision date:	7/16/24

Revision Log		
1	1/6/2005	
2	2/6/2012	Reformat – revise interval reference.
3	11/1/2012	Clarify field load reading requirements.
4	12/17/2019	Incorporate Berkshire Hathaway Energy (BHE) Mission 3 requirements into policy.
5	7/16/2024	Updating to include Oracle Field Service data capturing method.

Document Security Category			
	Confidential		External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

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Policy

SUBSTATION INSPECTION

Asset Management Policy No. 034

1 Purpose

This policy provides the general requirements and objectives for the performance of physical inspections of substation facilities associated with the transmission and distribution system owned by PacifiCorp.

2 References

- Pacific Power Policy 001-PP *Maintenance Intervals for Apparatus, Relays, Line Patrol/Inspections and Communications Equipment*
- Rocky Mountain Power Policy 001-RMP *Maintenance Intervals for Apparatus, Relays, Line Patrol/Inspections and Communications Equipment*
- PacifiCorp Policy No. 166, *Maintenance and Inspection Records*
- PacifiCorp Form 3274F, *PacifiCorp T&D Substation Inspection*
- Pacific Power Form 3274S, *Substation Security Inspection*
- Rocky Mountain Power Form 3274S, *Substation Security Inspection*

3 Objective

Substation inspections include a visual inspection of substation components, performance of minor testing or operational tasks, performance of minor housekeeping tasks and the recording of various equipment readings and measurements. The purpose of these tasks is to check the security of the substation, note obvious defects in equipment installation or performance, verify the physical operation of certain equipment and record data that is used by others for load planning or maintenance planning purposes. Discrepancies or issues found during the performance of inspections may be corrected on site immediately, or noted on the inspection documentation and prioritized for later repair.

3.1 Intervals: Substations shall be inspected on a periodic basis per the intervals and requirements listed in either Policy 001-PP for Pacific Power locations, or Policy 001-RMP for Rocky Mountain Power Locations.

3.2 Scope: The requirements for the scope of substation inspections are as listed on forms 3274F, 3274S-PP, 3274S-RMP and the equivalent electronic forms stored in Maximo and Oracle Field Service. Inspections performed without Oracle Field Service shall use forms 3274F and either 3274S-PP for Pacific Power locations or 3274S-RMP for Rocky Mountain Power locations. Inspections performed using Oracle Field Service shall use the electronic forms stored in Maximo and Oracle Field Service. Field offices may use these forms, or their functional equivalents, which may be customized for each individual substation. The scope of a substation inspection includes:

1. Substation security inspection
2. Substation physical inspection / operational tests
3. Recording operational counters and load readings

3.3 Frequency: The frequency of inspections and/or their components are determined by Policy 001. However, substation security inspections are not to be longer than six months apart.

3.4 Deficiencies: Where applicable, deficiencies identified during the substation security inspection pertaining to substation security controls will be corrected within 30 days to ensure adherence to Berkshire Hathaway Energy Mission 3 cybersecurity requirements. Where 30-day correction of this subset of deficiencies is not possible, compensating controls must be implemented to mitigate associated risks until the defficiency can be corrected. The specific subset of deficiencies pertaining to substation security controls that require this 30-day correction are noted on both versions of Form 3274S.

3.5 Documentation : Inspection records shall be stored and retained per the requirements of Policy 166, *Maintenance and Inspection Records*.

3.6 Use of SCHOOL System: It is preferred that load readings be recorded with the use of SCHOOL handheld computers. The readings are then uploaded to the SCHOOL sytem. As an alternative, readings may be taken manually and then entered into SCHOOL using the Manual Logger PC Software. For stations with SCADA where readings are entered into school directly from the SCADA system, field readings need not be taken.

Rocky Mountain Power | Pacific Power

MAINTENANCE INTERVALS FOR APPARATUS, RELAYS, METERS, LINE PATROL/INSPECTIONS, WIRES EQUIPMENT AND COMMUNICATIONS EQUIPMENT

PacifiCorp Asset Maintenance and Compliance Policy 001

Date	Revision #	Notes
…		
12/8/2017	36	Updated maintenance ID for Meters M4, M5 and M6. On Relay tab added new Throwover, Autosource transfer and Air cooled Xfmr maintenance tasks; and removed V1-VBE and S2 maintenance activity. On Apparatus tab added synchronous condenser testing; updated OFIN-xxx; cycle is to be determined; also, updated TNOS-002 added Pacific Power BMMx-036 minor maintenance. On Comm tab modified equipment information.
8/8/2018	37	Updated California Visual Assurance (Patrol) inspections to meet new requirements, corrected Hold Down Inspection policy inspection to Policy 337 from incorrect 377
12/14/2018	38	Line Inspec tab: Updated CA UG detail inspection note; added CA visual inspection to 1 year for Tier 1, 2 & 3; added Fuse Saver. Meter tab: Added CAISO/EIM meter intervals.
5/14/2019	39	Updated Relay Equipment Description for B1_B2 and U1_U2 to include "Monitored and Alarming to Scada", and correcting Maintenance Task for BR2 to "Minor". Correcting CA visual Tier notes.
3/24/2020	40	Maintenance Basis tab added note 3) regarding maintenance cycles less than 1 year. Apparatus tab added new line items for CKB, CAP, TRF and XRT for RMP only Warranty Inspections. Relay tab updated equipment description to "Electromechanical" for B5_B6 maintenance; added BR1 and BR2 to "Montitored alarming to scada" and add new plans BR3 and BR4 for recloser relays "Not Monitored"; also included Sudden Press in BR1, BR3 and BR4 notes. Line tab added Weather station 6 month inspections for RMP. Updated Recloser battery replacment model to 351R2 for RCBT(apc) and DRCL(line). Added FHCA new inspection cycles on Line tab. Added new maintenance activity OTN on Comm tab.
6/21/2021	0-PP	First version of Policy 001 specific to Pacific Power. Updated Communications man hours. Removed WMA maintenance task.
6/20/2022	1-PP	Added local transmission infrared line inspections (wires tab); RAS SPS1 maintenance interval changed from four years to six years (relay tab). Added B1_B2 maintenance to RAS SPS1 maintenance tasks (relay tab). Updated to include distribution breaker overhaul plans for large customers (apparatus tab). Added grid resilience equipment/storage facility inspection and maintenance task (apparatus tab).
6/30/2023	2-PP	Added non-FHCA Transmission Line Infrared Inspections for OR/WA (wires tab, line 15); Added non-NERC remedial action scheme maintenance items (relay tab, line 37 & 41).
10/13/2020	0-RMP	First version of Policy 001 specific to Rocky Mountain Power.
12/22/2020	1-RMP	Revision to update the policy on new transformer baseline DGA cycles.
2/12/2021	2-RMP	Revision to updated the policy on HVAC wall and window units and DGA and WARR on spare transformers; updated DCAP cycle.
9/20/2021	3-RMP	Removed "window" from HVAC maintenance; Combined the DGA on Spare transformers with the Designated/Strategic Spares. Removed MWA and updated TOW hours and notes from Communications tab. Added Synchronous Condenser 5-year & monthly maintenance and 5-year operating validation. Removed 4-month XROS and OFIN plans.
2/9/2022	4-RMP	Updated maintenance basis explanation for non-WECC apparatus and relay work orders. Added synchronous condenser PRC-019 maintenance requirements. Changed RAS maintenance plan cycle from 4 to 6 years per PRC-005. Added MWA and Alarm GMP plans on Communication tab.
2/9/2023	5-RMP	Updated weather station maintenance plan cycle from 6 months to 1 year. Updated weather station maintenance plan type from EML4 to EML8. Updated cap bank interval from 2 and 4 years to 1 year on GE.

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9/18/2023	6-RMP	Added RAS Component maintenance B1_B2; in addition add maintenace for any potential Non-WECC/NERC RAS systems and their components. Removing TNOS specific Plan; noting TROS and XROS plans are to begin 2 months after commissioning. Added DRCL Siemens CMR maintenance. Additional maintennace added for GE SCAP and Sync Condensors. Added STATCOM Maintenance
1/19/2024	7-RMP	Wires tab: Added infrared Inspections to FHCA transmission lines. Added annual inspections on underground transmission lines. Distribution PTT and UG Detail Inspection cycles change from 20-year to 10-year. Adding switchgear infrared inspections. Add SEL AR360 fault indicator unit replacement.
11/4/2024	41	disclaimer. Added Syn Conderson MIN mtc for Goshen. Added PRC-027 Setting requirements, under relay. Separated out Wires Inspections and Equipment into two tabs. DRCL-MAJ added to Wires Equipment tab. Separated out Wires Inspections by State from wires equipment.
5/5/2025	42	Added FAA Inspections on the Wires Equipment tab. Pacific Power UGIN cycle change. Pacific Power CA & WA PTT cycle change to 10yr. WA UG Detail cycle change to 10yr.

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** between 10/31/20 and 11/4/24 there was a separate Rocky Mountain Power version of this policy. Between 6/21/21 and 11/4/24 there was a separate Pacific Power version of this policy. As of 11/4/24 the policy has been reintegrated as a single PacifiCorp document.*

The most current version of this document is posted to engineering's policy websites.

Revisions to this document must be made by the authoring department and posted by engineering publications (eampub@pacificorp.com)

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Maintenance Basis

Apparatus	Apparatus maintenance intervals for PacifiCorp are based on a combination of manufacturer's recommendations, failure and corrective maintenance history and experience and the opinions of PacifiCorp subject matter experts. The maintenance intervals are time based, are based on operations counts or based on other triggers.
	The following pertains to apparatus equipment designated as a component of a NERC FAC-501 critical path: 1) Time intervals are developed assuming the required preventative maintenance work will be performed within the calendar year the order is generated with the stated interval being defined as calendar years. 2) For work on equipment that is triggered by an operational counter, the work shall be performed within the calendar year following the counter trigger date. 3) For time intervals less than one year (i.e. 3 months, 4 months, etc.) the preventative maintenance work will be performed within the cycle time period.
	Testing or maintenance activities that call for operation of the equipment may be satisfied if an actual real-time operation of that device can be documented during the last maintenance cycle.
	Maintenance intervals and requirements are reviewed on a periodic basis and adjusted based on failure or maintenance issues, industry trends and manufacturer's recommendations.

Maintenance Deferral for NERC Equipment	Maintenance due in a given calendar year for apparatus equipment designated NERC in Maximo may be deferred if an approved capital replacement project for the equipment is scheduled for the following calendar year or if materials, parts or required expertise are unavailable, delaying work. The maintenance order will be closed when the replaced equipment is placed in-service and a new maintenance plan will be assigned to the replaced equipment. NERC relay maintenance must be completed within caledar year due and cannot be deferred for any NERC in-service equipment.

Maintenance Deferral for Non-NERC Equipment	Work orders and maintenance for non-NERC equipment may be deferred due to operational priorities, approved capital projects or maintenance projects.

Maintenance Actual Finish Dates	Work orders Actual Finish Dates can differentiate from completion date on form due to the new system functionality.

New or Revised Maintenance Policies	Upon creation or revision of a maintenance policy, the determination of when the new maintenance activity will commence on an individual piece of equipment will be determined by PacifiCorp Asset Management. Equipment will not be considered non-compliant with the new or revised maintenance policy interval if the work required per this policy is completed within the calendar year of the initial call date that was assigned to that equipment by PacifiCorp Asset Management.

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Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Battery**	Vented or NiCad	NERC - Bulk Electrical System	All	All	N/A	Battery Inspection	BATTERY	BTTI	4 Months	4	N/A	Battery inspection.	
PP & RMP	**Battery**	Valve Regulated	NERC - Bulk Electrical System	All	All	N/A	Battery Maintenance	BATTERY	BTTM	4 Months	4	N/A	Battery impedance test.	
PP & RMP	**Battery**	Vented or NiCad	NERC - Bulk Electrical System	All	All	N/A	Battery Maintenance	BATTERY	BTTM	18 Months	18	N/A	Battery impedance test.	
PP & RMP	**Battery**	Vented, NiCad or Valve	Transmission and Distribution (Non-NERC)	All	All	N/A	Battery Maintenance	BATTERY	BTTM	2	24	N/A	Battery impedance test.	
PP & RMP	**Battery**	Sodium Nickel	All	All	All	N/A	N/A	BATTERY	N/A	N/A	N/A	N/A	No maintenance required on these batteries	2024
RMP	**Battery Energy Storage System**	BESS Site		All	All	N/A	Annual Inspection	N/A	BESS	1	12	N/A	Annual inspection of BESS site as indicated on the maintenance form (Panguitch Solar Battery Site).	2020
RMP	**Battery Energy Storage System**	UPS Battery		All	All	N/A	Battery Replacement	BAT_UPS	UPS BATTERY	3	36	N/A	Replace UPS batteries.	2020
RMP	**Battery Energy Storage System**	Fire Suppression System		All	All	N/A	Inspection	FSS	FSS	6 Months	6	N/A	Inspection to be completed by a third party.	2020
RMP	**Battery Energy Storage System**	Solar Panels		All	All	N/A	Infrared Testing by Drone	N/A	SINF-DRONE	1	12	N/A	Infrared testing of solar panels with the use of a drone.	2020
PP & RMP	**Circuit Breakers**	Breaker Battery		All w/UPS	All w/UPS	N/A	Circuit Breaker Battery Replacement	BREAKER	BKBT	3	36	N/A	Circuit breaker battery replacement.	
PP & RMP	**Circuit Breakers**	Recloser Battery		All (except Hydraulic - see Notes column)	All	N/A	Recloser Battery Replacement	RECLOSER	RCBT	3	36	N/A	Recloser battery replacement. Hydraulic reclosers do not have batteries, and do not need maintenance plans.	
PP & RMP	**Circuit Breakers**	Recloser Battery		G&W Viper	with SEL-351R Controllers	N/A	Recloser Battery Replacement	RECLOSER	RCBT	2	24	N/A	Recloser battery replacement.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil		All	All	All Voltages	Warranty Inspection	BREAKER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil	Except Transformer Low Side Circuit Breaker with no Bypass, or 35kV and Below Cap Bank and Others as Approved by Asset Management	All	All	All Voltages	Exercise Breaker	BREAKER OR RECLOSER	BIOA	1	12	N/A	Yearly operational test. May be fulfilled by documentation of an actual operation.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil	NERC - FAC-501 Critical Path	All	All	All Voltages	Exercise Breaker	BREAKER OR RECLOSER	BIOA	1	12	N/A	Yearly operational test. May be fulfilled by documentation of an actual operation.	
PP & RMP	**Circuit Breakers**	Air	Tertiary Fed Reactor, Cap Bank, Station Service, Synchronous Condenser	All	All	12kV to 34.5kV	Overhaul	BREAKER	BOHA	6	72	N/A		
PP	**Circuit Breakers**	Air	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Minor Maintenance	BREAKER	BMMA	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Air	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Overhaul	BREAKER	BOHA	9	108			
PP	**Circuit Breakers**	Air	All applications except bus, cap and low side transformer	All	All	35kV and Below	Overhaul	BREAKER	BOHA	0	Counter Based	50-Fault	Counters applied per Asset Management.	

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Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP	**Circuit Breakers**	SF6 gas	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Minor Maintenance	BREAKER	BMMS	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Capacitor or Reactor Without Zero Crossing Controls	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	8	96		Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Reactor with Zero Crossing Controls	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	6	72	N/A	Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Reactor with Zero Crossing Controls	All	All	40kV and Above	Control System Download	BREAKER	BXRT	2	24	N/A	Meter/Relay to download oscillography data and forward to Apparatus Tech Support for review of proper timing. Submit to Asset Management	9/3/2020
RMP	**Circuit Breakers**	SF6 Gas	Capacitors with Zero Crossing Controls	Asea-Brown Boveri	PMI	40kV and Above	Control System Download	BREAKER	BXRT	2	24	N/A	Meter/Relay to download oscillography data and forward to Apparatus Tech Support for review of proper timing. Submit to Asset Management	
PP & RMP	**Circuit Breakers**	SF6 Gas Puffer	Line, Transformer, Bus	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	10	120	N/A		
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure	Line, Transformer, Bus	All (except for mfg and models listed below)	All (except for mfg and models listed below)	40kV and Above	Minor Maintenance	BREAKER	BMMS	4	48	N/A	Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure		ITE	GA	230kV- 500kV	Overhaul	BREAKER	BOHS	6	72	N/A	These models have overhauls only, no minor maintenance.	
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure		Westinghouse	2300-SF-15000	230kV	Overhaul	BREAKER	BOHS	6	72	N/A	These models have overhauls only, no minor maintenance.	
PP	**Circuit Breakers**	SF6 Gas, Dual Pressure		Westinghouse	SFA	230kV- 500kV	Overhaul	BREAKER	BOHS	8	96		These models have overhauls only, no minor maintenance.	
PP	**Circuit Breakers**	SF6 gas bottles	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER	BMMS	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	SF6 gas	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER	BOHS	9	108			
PP	**Circuit Breakers**	SF6 gas bottles (sealed module)	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER	BOHS	0	Counter Based	50-Fault	Counters applied per Asset Management. Pacific Power ONLY.	
PP & RMP	**Circuit Breakers**	Oil	Capacitor or Reactor	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMO	6	72			
PP & RMP	**Circuit Breakers**	Oil	Line, Transformer, Bus	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMO	6	72	N/A		
PP	**Circuit Breakers**	Oil	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER	BMMO	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Oil	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER	BOHO	6	72			
PP	**Circuit Breakers**	Oil	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER	BOHO	0	Counter Based	30-Fault	Counters applied per Asset Management.	
PP & RMP	**Circuit Breakers**	Vacuum	Tertiary Fed Reactor, Cap Bank	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	8	96	N/A		
PP & RMP	**Circuit Breakers**	Vacuum	Tertiary Fed SVC, Wind Site Breakers.	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	10	120	N/A		
PP & RMP	**Circuit Breakers**	Vacuum	Synchronous Condenser	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	6	72	N/A		
PP	**Circuit Breakers**	Vacuum	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER OR RECLOSER	BMMV	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Vacuum	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER OR RECLOSER	BOHV	9	108			

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Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP	**Circuit Breakers**	Vacuum	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER OR RECLOSER	BOHV	0	Counter Based	50-Fault	Counters applied per Asset Management.	
PP & RMP	**Circuit Switcher**	Gas	Reactive Switching, Line Switching or Transformer Protection	S&C Electric Siemens Allis	Type G, Mark Series Linebacker	100kV or Above	Inspect & Operate	CIRSWR	CSIO	5	60	N/A	Inspect and test.	
PP & RMP	**Circuit Switcher**	Gas	NERC - FAC-501 Critical Path	S&C Electric Siemens Allis	Type G, Mark Series Linebacker	100kV or Above	Inspect & Operate	CIRSWR	CSIO	5	60	N/A	Inspect and test.	
PP & RMP	**Circuit Switcher**	Gas	No Physical Counter	All	All	All Voltages	Overhaul	CIRSWR	CSOH	8	96	N/A		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric	2000 Series	All Voltages	Overhaul	CIRSWR	CSOH	N/A	Counter Based	3,000-Ops		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric Siemens Allis Southern States	Type G, Mark Series (Mark V - 1984 or newer) Linebacker, CPV2 CSV	All Voltages	Overhaul	CIRSWR	CSOH	N/A	N/A	1,500-Ops		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric	Mark V - 1983 or older	All Voltages	Overhaul	CIRSWR	CSOH	N/A	N/A	1,000-Ops		
PP & RMP	**Fuse**	All Spare Power Transformer Fuses		S&C Electric SMD Fuses		N/A	Air Flow Test	N/A	FUSE	5	60	N/A	Air flow test.	
PP & RMP	**Generator**	Emergency		All	All	N/A	Annual Inspection	GENERATOR	EPUA	1	12	N/A		
RMP	**Generator**	Mobile	Terminal	All	All	N/A	Start-up & Inspect	GENERATOR	MOGN	Monthly	1	N/A	Monthly start-up and inspection on mobile generators on Barron oil trailers.	
PP	**GRID RESILIENCE STORAGE FACILITY**	Grid resilience facility					GR Equipment/Bldg Inspection	N/A	GRID	4 Months	4	N/A	Inspection of grid resilience equipment and storage facility	
PP & RMP	**HVAC**	Air Conditioning/Heating Systems		All	All	N/A	Inspect & Operate	HVAC	HVAC	1	12	N/A		
RMP	**HVAC**	Wall Units		Bard Mitsubishi	All All	N/A	Inspect & Operate	HVAC	HVAC	1	12	N/A		2021
PP & RMP	**Reactors**	All Types, including Spares	All Applications	All	All	All Voltages	Warranty Inspection	REACTOR	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Reactors**	Oil Filled	All Applications	All	All	All Voltages	DGA & Oil Quality Tests	REACTOR	XROS	1	12	N/A	DGA and oil quality for reactor tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called annully thereafter.	
PP	**Reactors**	Oil Filled		ABB		345kV, 500kV	DGA and Oil Quality Tests	REACTOR	XROS	4 Months	4	N/A	DGA and oil quality for reactor tank. NOTE: Work orders generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Regulator LTC**	Vacuum LTC in 3 Phase Regulator		Cooper Power	V2A	N/A	DGA Tests	REGLTC	TCOS	1	12	N/A	DGA for LTC tank.	
PP & RMP	**Regulator LTC**	Non Vacuum with Separate LTC Tank on 3 Phase Regulator		General Electric Cooper Power Westinghouse	MLT32 550BLS and SVR URS, URT and UTT	N/A	DGA Tests	REGLTC	TCOS	4 Months	4	N/A	DGA for LTC tank. NOTE: Work orders are generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Regulator LTC**	3 Phase with Non Vacuum LTC		All	All	All Voltages	Overhaul	REGLTC	RGOH	4	48	N/A	Inspect contacts & filter oil.	
PP & RMP	**Regulator LTC**	3 Phase with Vacuum LTC		Cooper Power	V2A	All Voltages	Overhaul	REGLTC	RGOH	8	96	N/A	Inspect contacts & filter oil.	
PP & RMP	**Regulators**	3 Phase with LTC in Tank		Allis Chalmers General Electric	AFR and SFR TMLT32	All Voltages	DGA & Oil Quality Tests	REGULATOR	RGOS	4 Months	4	N/A	DGA and oil quality for regulator main tank. NOTE: Work orders are generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Regulators**	3 Phase with LTC in Separate Tank		General Electric Cooper Power Westinghouse	MLT32 550BLS and SVR URS, URT and UTT	All Voltages	DGA & Oil Quality Tests	REGULATOR	RGOS	1	12	N/A	DGA and oil quality for a regulator's main tank.	

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Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Series Capacitor**	Under 10 years old		All (exclude GE)	All	All Voltages	Inspection	CAPBANK	SCIN	4	48	N/A	On platform equipment	
PP & RMP	**Series Capacitor**	Over 10 years old		All (exclude GE)	All	All Voltages	Inspection	CAPBANK	SCIN	2	24	N/A	On platform equipment	
PP & RMP	**Series Capacitor**	All Years		General Electric	All	All Voltages	Inspection	CAPBANK	SCIN	1 (sequence with SCMT)	12	N/A	On platform equipment	Apr-23
PP & RMP	**Series Capacitor**	All Years		General Electric	All	All Voltages	Maintenance	CAPBANK	SCMT	5 (sequence with SCIN)	60	N/A	On platform equipment	May-23
PP	**Series Capacitor**	With air gap trigger		N/A	N/A	N/A	Air Gap Injection	CAPBANK	ARGP	0	Counter Based	25 Operations	Burns Reactor Sub only	
RMP	**Shunt Capacitor**	All Types		All	All	40kV and Above	Warranty Inspection	CAPBANK	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on the manufacture date. One time only plan.	
PP & RMP	**Spare Equipment**	Strategic Spare Equipment Located in Tech Ops Yard/Bldg.		All	All	All Voltages	Spare Equipment Inspection	N/A	SPAR	4 Months	4	N/A	Inspection of strategic spares in yard.	
RMP	**STATCOM**	Statcom System		All	All	All Voltages	Inspection	N/A	STATCOM-INSP	1 Month	1	N/A	Monthly inspection to be completed 8 times per year; same months as substation inspections	2023
RMP	**STATCOM**	Statcom System		All	All	All Voltages	PM	N/A	STATCOM-PM	1 Year	12	N/A	Annual inspection to be completed by Contractor	2023
RMP	**Substation**	NERC TMIP Facility Pertaining to FAC-501 Critical Path Standard		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically. NOTE: For substations associated with NERC critical paths (FAC-501) a minimum of 10 monthly inspections shall be performed annually, with three of these monthly	
PP	**Substation**	NERC TMIP Facility Pertaining to FAC-501 Critical Path Standard		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN, SBIN-MAJ and SECURITY	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads/minor/major scope performed periodically. NOTE: Substations associated with NERC critical paths (FAC-501), a minimum of 10 monthly inspections shall be performed annually, with 3 of these monthly inspections being the more detailed "major."	
PP	**Substation**	Substations – Oregon		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN, SBIN-MAJ and SECURITY	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads/minor/major scope performed periodically. NOTE: Inspections shall be performed monthly, with no longer than 45 calendar days between consecutive inspections.	
RMP	**Substation**	Non-NERC All Facilities Including Mobiles		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly (8 times per year)	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically.	
PP	**Substation**	Non-NERC All Facilities - California & Washington Including Mobiles		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly (8 times per year)	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically.	
RMP	**Substation**	All Pole Mount Sites; Facility with No Electrical Exposure/Fence Requirement		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MAJ	1	12	N/A	Inspect pole mounts, collector sites or other facilities with no electrical exposure / fence requirement.	

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PP	**Substation**	Pole mount/other facility with no electrical exposure, fence requirement. Excludes FII sites.		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	OFIN	VARIES	N/A	N/A	Interval determined by Asset Management. Inspect pole mounts, collector sites (4 months) or other facilities with no electrical exposure/fence requirement.	
PP & RMP	**Substation**	Distribution Facility, FII, Pole Mount		N/A	N/A	All Voltages	Infrared Testing	N/A	SINF	2	24	N/A	Infrared testing of substation bus, switches & major equipment.	
PP & RMP	**Substation**	Transmission Facility		N/A	N/A	All Voltages	Infrared Testing	N/A	SINF	1	12	N/A	Infrared testing of substation bus, switches & major equipment.	
PP & RMP	**Substation**	Substation Security System		N/A	N/A	All Voltages	Inspection	N/A	SSS	3	36	N/A	AVTEC contracted to inspect the substation security system. Company required to chaperone AVTEC during the inspection. Compliance identifies security sites.	
PP	**Substation**	Wood Poles		N/A	N/A	All Voltages	Detail, Pole Test & Treat	MISC	WOOD	10	120	N/A	Wood pole within substation fence will be inspected, tested or treated per company's PTT policies. Inspections completed by OSMOSE and coordinated with sub-operations staff.	
RMP	**Synchronous Condenser**	Standpipe Sub		N/A	N/A	N/A	Major Maintenance	CONDENSER	SYNMAJ	5 (sequenced with ANN)	60	N/A	Standpipe Major and Annual maintenance are sequenced.	2024
RMP	**Synchronous Condenser**	Standpipe Sub		N/A	N/A	N/A	Annual Maintenance	CONDENSER	SYNANN	1 (sequenced with MAJ)	12	N/A	Standpipe Major and Annual maintenance are sequenced.	2024
RMP	**Synchronous Condenser**	Goshen Sub		N/A	N/A	N/A	Major Maintenance	CONDENSER	SYNMAJ	5 (sequenced with MIN)	60	N/A		2024
RMP	**Synchronous Condenser**	Goshen Sub		N/A	N/A	N/A	Minor Maintenance	CONDENSER	SYNMIN	5 (sequenced with MAJ)	60	N/A		2024
RMP	**Synchronous Condenser**	Goshen and Standpipe Subs		N/A	N/A	N/A	Inspection	CONDENSER	SYNMON	Monthly	1	N/A	Monthly Inspection; complete form	2021
RMP	**Synchronous Condenser**	Goshen and Standpipe Subs	NERC	N/A	N/A	N/A	Verify Relay Setting Orders; If Changed, Coordination Study Required	CONDENSER	PRC19	5	60	N/A	5 Year Setting Order Verification; If study is required, an EMS3 order will be created; order must be completed within the year	2022
RMP	**Synchronous Condenser**	Goshen and Standpipe Subs	NERC	N/A	N/A	N/A	Verify Operating at Nameplate Capacity	CONDENSER	MOD25	5	60	N/A	5 Year Verification	
PP & RMP	**Synchronous Var Controller (SVC)**	Thyristor Switched		All	All	All Voltages	Inspection/Checkout	SVC	SVCI	2	24	N/A	De-energized inspection/checkout per SVC maintenance checklist.	
PP & RMP	**Tank**	Oil/Fuel Storage Tank		All	All	N/A	Inspection	FTANK or OTANK	TKIN	1	12	N/A	Inspection of oil or fuel storage and trailer mounted tanks.	
PP & RMP	**Tank**	Oil/Fuel Storage Tank, Above Ground		All	All	N/A	Certified Tank Inspection	FTANK or OTANK	TKTS	20	240	N/A	Certified tank inspection performed by STI certified tank inspector per PacifiCorp policy 216 & Steel Tank Institute (STI) document SP001 Section 4.	
PP & RMP	**Tank**	SF6 Cylinder Trailers/Carts		All	All	N/A	Inspection	FTANK or OTANK	SF6C	5	60	N/A	Hammer or ring test SF6 cylinders on handcart and trailers.	
PP & RMP	**Transformer**	1 Phase and 3 Phase		All	All	40kV and Above (High Side)	Warranty Inspection	PTRANSFORMER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Transformer**	1 Phase	All energized transformers	All	All	Below 230kV (High Side) and 2.5-59 MVA (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	3	36	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called every 36 months thereafter.	
PP & RMP	**Transformer**	3 Phase	All energized transformers	All	All	Below 230kV (High Side) and 5-59 MVA (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	3	36	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called every 36 months thereafter.	
PP & RMP	**Transformer**	1 or 3-Phase	All energized transformers	All	All	230kV and Above (High Side) or 60 MVA and Above (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called annully thereafter.	

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Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Transformer**	Over 40 years old	All energized transformers	All	All	All Voltages	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	Over 40 years old. DGA and oil quality for transformer tank.	
PP & RMP	**Transformer**	Mobile		All	All	All Voltages	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	DGA and oil quality for transformer tank.	
PP & RMP	**Transformer**	Non-Energized Spares		All	All	All Voltages	Oil Quality Tests	PTRANSFORMER	TROS	2	24	N/A	Oil quality for transformer tank of non-energized spares.	
PP & RMP	**Transformer**	Spare		All	All	All Voltages	Warranty Inspection	PTRANSFORMER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	2021
PP & RMP	**Transformer LTC**	Reactive or Resistive		All	All	N/A	DGA Tests	TRFLTC	TCOS	4 Months	4	N/A	DGA for load tap changer only NOTE: Work orders generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Transformer LTC**	Vacuum		Reinhausen Mfg. Cooper Power General Electric	RMV and VR V1 and V2 LRT-200 and LRT-	N/A	DGA Tests	TRFLTC	TCOS	1	12	N/A	DGA for load tap changer only.	
PP & RMP	**Transformer LTC**	Reactive With or Without Filter	All Applications and Mobiles	Federal Pacific McGraw Edison	TC-525 and 546 550	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Reactive Without Filter	All Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Reactive With Filter	Distribution Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Reactive With Filter	Transmission Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Resistive Without Filter	All Applications and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Resistive With Filter	Distribution Applicaton and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	9	108	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Resistive With Filter	Transmission Applications and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Reinhausen Cooper	RMV V1 and V2	N/A	Overhaul LTC	TRFLTC	TCOH	12	144	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Reinhausen	VR	N/A	Overhaul LTC	TRFLTC	TCOH	N/A	N/A	300,000 Ops	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Cooper	LRT-200 and LRT-500	N/A	Overhaul LTC	TRFLTC	TCOH	8	96	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B2 Equip Code. B2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	B2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, trip coils if 2 coils present. NOTE: Maintenance shall be scheduled 6 years offset from B1 Equip Code. B2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B3-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B4 Equip Code. B4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Not Monitored**	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B4-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B3 Equip Code. B4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B5-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B6 Equip Code. B6 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B6-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall protection package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B5 Equip Code. B6 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Electronic or Electromechanical Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B7-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B8 Equip Code. B8 is scheduled first - 6 years after commissioning;	
PP & RMP	**NERC Bulk Electrical System**	Electronic or Electromechanical Relay Protection System	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B8-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall protection package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B7 Equip Code. B8 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Programmable Logic Controller (PLC) Based Protection Systems for Series Capacitor Banks or Other Devices	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and	B9-MAJ/CTRL	6	MAJ/CTRL	Test overall protection package, CT/PT's, auxiliary relays, control wiring per procedures, trip coils if 2 present.	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 Monitored and Alarming to SCADA	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	BR1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR2 Equip Code. BR2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	BR2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - Maintain non-monitored relays per procedures, trip coils if 2 coils present NOTE: Maintenance shall be scheduled 6 years offset from BR1 Equip Code. BR2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	BR3-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR2 Equip Code. BR4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Not Monitored**	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	BR4-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR3 Equip Code. BR4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	BES Settings Review PRC-027	Review BES relay settings	PRC-027	6	N/A	P&C Engineer will review settings on BES relay, one year prior to the BES scheduled maintenance.	2025
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and	U1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from U2 Equip Code. U2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	U2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - Maintain non-monitored auxiliary relays per procedures. NOTE: Maintenance shall be scheduled 6 years offset from U1 Equip Code. U2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry	U3-MAJ/CTRL	6	MAJ/CTRL (INSRVC)	Test overall relay package, CT/PT's and control wiring.	
PP & RMP	**NERC Under Frequency and Under Voltage**	Electronic or Electromechanical Relay Protection System-Load Shed	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry	U4-MAJ/CTRL	6	MAJ/CTRL (INSRVC)	Test overall relay package, CT/PT's and control wiring.	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Transmission (Non-NERC)**	Microprocessor Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL	Functional test overall relay package, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes. NOTE: Maintenance shall be scheduled 6 years offset from T2 Equip Code. T2 is scheduled first - 6 years after commissioning.	
PP & RMP	**Transmission (Non-NERC)**	Microprocessor Relay Protection System	Minor: Settings, Test Auxiliary's and Verify Inputs	T2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, NOTE: Maintenance shall be scheduled 6 years offset from T1 Equip Code. T2 is scheduled first - 6 years after commissioning.	
PP & RMP	**Transmission (Non-NERC)**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T3-MAJ/CTRL	6	MAJ/CTRL	MP diagnostic, perform relay functional test and element testing of EM/EE relays, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Transmission (Non-NERC)**	Electromechanical or Electronic Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T4-MAJ/CTRL	6	MAJ/CTRL	Perform relay functional test and element testing of EM/EE relays, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Transmission (Non-NERC)**	Auto - Throwover	Perform Relay Functional Test and Decouple and Operate Motor Operators	T5-ATOS	6	ATOS	Not subject to PRC-005 standard requirements	
PP & RMP	**Distribution (Non-NERC)**	Microprocessor Relay Protection System	Test & Calibrate Relay Package and Components	D1-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Distribution (Non-NERC)**	Electromechanical or Electronic Relay Protection System	Test & Calibrate Relay Package and Components	D3-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Distribution (Non-NERC)**	Fuse Protected, Transformer	Test & Calibrate Relays / Devices	D4-CTRL	12	CTRL	Test Thermal / Other Relays	
PP & RMP	**Distribution (Transformer) (Non-NERC)**	Electromechanical or Electronic Relay with Capacitive Components Protection System on Transformer	Test & Calibrate Relay Package and Components	D5-MAJ/CTRL	6	MAJ/CTRL	Perform relay element testing of EM/EE relays / test auxiliary relays. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**HMI**	Automated Substation	Replace CPU Battery	S3-HMI	5	N/A	Replace CPU battery.	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Remedial Action Scheme Functional Testing	SPS1	6	Functional Testing	Maintain per PRC-005-RAS requirements including functional test. Note: If components exist in SPS1 package; B1_B2 maintenace will also be present on all relay packages for the RAS. Only 1 SPS1 plan per RAS, usually the PM is placed on the Substation that the RAS is named after, if not refer to the annual Transmission Planning RAS spreadsheet or to Scott Hillis.	change from 4 yr cycle to 6 yr cyle 1/2022
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Major and Control: test and calibrate overall relay package, control circuitry, CTs, PTs and control circuitry	B1-MAJ/CTRL	12	MAJ/CTRL (INSRVC)	Test overall relay package including sudden pressure if present, CT/PTs, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present, verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B2 Equip Code. B2 is scheduled first, 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Minor: settings, test auxiliaries, verify inputs	B2-MIN	12	MIN	Verify inputs and settings, download history. Maintain non-monitored relays per procedures, trip coils if 2 coils present. NOTE: Maintenance shall be scheduled 6 years offset from B1 Equip Code. B2 is scheduled first, 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Remedial Action Scheme Functional Testing	SPSN	6	Functional Testing	Maintain per PRC-005 requirements including functional test. Note: If components exist in SPSN package; T1_T2 maintenace will also be present on all realy packages for the RAS.	3/2023 Added to cover Non-WECC/NERC RAS Systems
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Major and control: test and calibrate overall relay package, control circuitry, CTs and PTs and control circuitry	T1-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes. NOTE: Maintenance shall be scheduled 6 years offset from T2 Equip Code. T2 is scheduled first - 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Minor: A/D, settings, auxiliaries	T2-MIN	12	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, NOTE: Maintenance shall be scheduled 6 years offset from T1 Equip Code. T2 is scheduled first - 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP	**Relay - Doble Test Equip**	Doble F6150 test equipment	Test and calibrate relay test set	TEST	1	N/A	Perform annual calibration of Doble F6150	

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Site	Equipment	Equipment Types	Equipment Use	Witness	Form(s) to Submit	Interval Years	Job Plan ID	Notes	Policy Effective Date/Year (if known)
PP & RMP	**Meter Package**	Intertie Meters (Interchange Meter as Defined by NERC BAL-005)	PAC-Owned NERC	YES	Form 129F	2	M1-MTR or M1-REL	Test Document 129F must have the NERC/WECC portion populated on at least one	
PP & RMP	**Meter Package**	Intertie Meters (Interchange Meter as Defined by NERC BAL-005)	Foreign-Owned	YES	Foreign Utility Test Form & Form 130F	Varies	M2-MTR or M2-REL	Interval determined by other utility.	
PP & RMP	**Meter Package**	Borderline or PAC Gen Meters	PAC-Owned Non-NERC	YES	Form 129F	2	M3-MTR or M3-REL		
PP & RMP	**Meter Package**	Borderline or Cust Gen Meters	Foreign-Owned Non-NERC	YES	Foreign Utility Test Form & Form 130F	Varies	M4-MTR or M4-REL	Interval determined by other utility.	
PP & RMP	**Meter Package**	Borderline, Gen Retail, PAC Gen or Load Meters	PAC-Owned Non-NERC	NO	Form 129F	2	M5-MTR or M5-REL	Load - Meters used for retail loads that provide SCADA to the EMS	
PP & RMP	**Meter Package**	Check or Stateline Meters	PAC-Owned Non-NERC	NO	Form 129F	5	M6-MTR or M6-REL		
PP & RMP	**Meter Package**	Retail	PAC-Owned Non-NERC	NO	None	Varies	Maintained in CSS	Retail - Meter used for retail load outside of a substation.	
PP & RMP	**Meter Package**	CAISO/EIM Meters	PAC-Owned	NO	Form 129F	2	Various		
PP & RMP	**Meter Package**	CAISO/EIM Meters	Foreign-Owned	YES	Foreign Utility Test Form & Form 130F	2	Various		

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1	NOTE: CA PUC maximum interval is 2 years plus 3 calendar months from the previous inspection for Non-Tier and Tier 1 areas. Change from 2 year cycle to 1 year cycle (effective 1/1/2025)	2025
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	NOTE: CA PUC maximum interval is 5 years plus 3 calendar months from the previous detail inspection. Note: Detail is combined with PTT on PTT years	
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If detail and PTT are combined in one task, per CA PUC the combined inspection must be performed no later than 5 years and 3 months from the previous detail inspection. Maximum interval between PTT inspection is 20 calendar years. Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1	NOTE: CA PUC maximum interval is 1 year plus 3 calendar months from the previous inspection for Tier 2 and Tier 3 areas in CA. *** Tier 3 must have at least one (1) inspection completed by June 30th. FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2019
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	NOTE: CA PUC maximum interval is 5 years plus 3 calendar months from the previous detail inspection. *** Tier 3 must have at least one (1) inspection completed by June 30th. Note: Detail is combined with PTT on PTT years FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2019
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If detail and PTT are combined in one task, per CA PUC the combined inspection must be performed no later than 5 years and 3 months from the previous detail inspection. Maximum interval between PTT inspection is 20 calendar years. *** Tier 3 must have at least one (1) inspection completed by June 30th. Cycle change from 20 year to 10 year, effective in 2026. FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2026
PP	**Distribution Circuit**	Underground Distribution Circuit	All	CA	Visual Assurance Inspection (V)	V-D-V-D	Map String	Standing Order	2	NOTE: CA PUC maximum interval is 2 years plus 3 calendar months from the previous inspection.	
PP	**Distribution Circuit**	Underground Distribution Circuit	All	CA	Detail Inspection (D)	D-V-D-V	Map String	Standing Order	4	Cabinets shall be opened and visually inspected (CA and OR only) Note: CA PUC maximum interval is 5 years plus 3 calendar months from previous inspection.	
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10		
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1		2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If Detail and PTT are combined in one task, the combined inspection must be performed no later than 5 years. Maximum interval between PTT inspection is 10 calendar years. Note: Detail and PTT is combined on PTT years	2020
PP	**Distribution Circuit**	Underground Distribution Circuit	All	OR	Detail Inspection (D)	n/a	Map String	Standing Order	10	Cabinets shall be opened and visually inspected (CA and OR only)	
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
~~**PP**~~	~~**Distribution Circuit**~~	~~Overhead Distribution Circuit~~	~~Non-FHCA~~	~~WA~~	~~Detail Inspection (D)~~	~~D&V-V-V-V-V-V-V-V-V-PTT-V-V-V-V-V-V-V-V-V~~	~~Map String~~	~~Standing Order~~	~~10~~	~~Note: Detail is combined with PTT on PTT years~~ Due PTT cycle increase to 10 year; stand alone detail inspections will be removed, effective 2026	~~2021~~
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1		2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Underground Distribution Circuit	All	WA	Detail Inspection (D)	n/a	Map String	Standing Order	10	Cycle change from 20 year to 10 year, effective in 2026.	2026
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	ID	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	ID	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-D-V-V-V-V-PTT&V	Map String	Standing Order	1		2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Detail Inspection (D)	D-V-V-V-V-PTT&V-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Detail Pole Test and Treat (PTT)	PTT&V-V-V-V-V-D=--V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years.	2020
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	UT	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-D-V-V-V-V-PTT&V	Map String	Standing Order	1		2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Detail Inspection (D)	D-V-V-V-V-PTT&V-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Detail Pole Test and Treat (PTT)	PTT&V-V-V-V-V-D=--V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years.	2020
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	WY	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1		
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	
PP	**Local Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Local Transmission Line**	Overhead transmission line	Glass ONLY Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1		

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PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	LOC-IR-024	2		
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	OR	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		
PP	**Local Transmission Line**	Overhead transmission line	FHCA	OR	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	
PP	**Local Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Local Transmission Line**	Overhead transmission line	Glass ONLY Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1	Note: As of 2024 there are no FHCA areas identified in Washington	
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR-024	2		
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	WA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1	Note: As of 2024 there are no FHCA areas identified in Washington	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	WA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: As of 2024 there are no FHCA areas identified in Washington Note: Sequenced with PTT Note: Detai is combined with PTT on PTT years	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: As of 2024 there are no FHCA areas identified in Washington Note: Sequenced with Detail	
PP	**Local Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Local Transmission Line**	Overhead transmission line	Glass ONLY Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	ID	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	

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RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	ID	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1	Note: As of 2024 there are no FHCA areas identified in Idaho	2024
PP	**Local Transmission Line**	Overhead transmission line	FHCA	ID	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1	Note: As of 2024 there are no FHCA areas identified in Idaho	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	ID	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: As of 2024 there are no FHCA areas identified in Idaho Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	
PP	**Local Transmission Line**	Overhead transmission line	FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: As of 2024 there are no FHCA areas identified in Idaho Note: Sequenced with Detail	
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	UT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		2020
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	UT	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	UT	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1		2024
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	**Local Transmission Line**	Overhead Transmission Line	Non-FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	WY	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		2020
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	WY	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	2020
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	
RMP	**Local Transmission Line**	Overhead Transmission Line	FHCA	WY	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1		2024
RMP	**Local Transmission Line**	Underground Transmission Line	All	UT	Detail Inspection	n/a	Plant Locality Number	LOC-UGIN-003	3 Months	Inspection is only on one UG transmission line PL#071003.	
RMP	**Local Transmission Line**	Underground Transmission Line	All	UT	Major Detail Inspection (MAJ)	MAJ-MIN-MAJ-MIN	Plant Locality Number	LOC-UGIN-MAJ	2	Inspection done on specific lines, which have UG points, by UG crews. NOTE: Maintenance shall be scheduled 2 years offset from Minor Detail Inspection. Minor is scheduled first.	2024
RMP	**Local Transmission Line**	Underground Transmission Line	All	UT	Minor Detail Inspection (MIN)	MIN-MAJ-MIN-MAJ	Plant Locality Number	LOC-UGIN-MIN	2	Inspection done on specific lines, which have UG points, by UG crews. NOTE: Maintenance shall be scheduled 2 years offset from Major Detail Inspection. Minor is scheduled first.	2024
PP	**Main Grid Transmission Line**	Overhead transmission line	All	CA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
PP	**Main Grid Transmission Line**	Overhead transmission line	All	CA	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
PP	**Main Grid Transmission Line**	Overhead transmission line	All	CA	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	

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PP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		
PP	**Main Grid Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Main Grid Transmission Line**	Overhead transmission line	Glass ONLY Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	
PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
PP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		
PP	**Main Grid Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Main Grid Transmission Line**	Overhead transmission line	Glass ONLY Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
PP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		
PP	**Main Grid Transmission Line**	Overhead Transmission Line	Non-FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR-024	2		
PP	**Main Grid Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	
PP	**Main Grid Transmission Line**	Overhead transmission line	Glass ONLY Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	AZ	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Arizona	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	CO	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Colorado	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	ID	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Idaho	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	MT	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Montana	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	

MAINTENANCE INTERVAL LIST
Communications

BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	NM	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in New Mexico	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	UT	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1		2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	WY	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1		2024

MAINTENANCE INTERVAL LIST
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BU	Equipment Type	Equipment Description	Equipment Use	Equipment Manufacturer or Model	State(s)	Maintenance Task	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP & RMP	**Recloser/Protection Devices**	Distribution Transfer Switch U/G	All	All	All	Operate MO	DTSW	DST-DTSW-060	5	Work coordinated by Wires.	
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	All (excluding G&W Viper w/SEL-351R Controllers)	All	Recloser Battery Replacement	DRCL	DST-DRCL-MIN-036	3	Line reclosers maintained by Substation Operations. Note: Sequenced with DRCL-MAJ PM Note: PP PM descriptions will not be updated until 2026; PP will continue to create PMs as DST-DRCL-036 stand alone.	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	G&W Viper with SEL-351R Controllers	All	Recloser Battery Replacement	DRCL	DST-DRCL-MIN-024	2	Line reclosers maintained by Substation Operations. Note: Sequenced with DRCL-MAJ PM Note: PP PM descriptions will not be updated until 2026; PP will continue to create PMs as DST-DRCL-024 stand alone.	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	All	All	Recloser Settings	DRCL	DST-DRCL-MAJ-072	6	Settings downloaded for review by Tech Ops and replace battery. Note: Sequenced with DRCL-MIN 2 year and 3 year PMs	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	Siemens CMR	All	Recloser Battery Replacement	DRCL	DST-DRCL-120	10	Line reclosers maintained by Substation Operations.	2023
PP & RMP	**Recloser/Protection Devices**	Distribution Fuse Saver	Circuits	All	All	Battery Replacement	FSV	DST-FSBT-060	5	Work coordinated by Wires.	
RMP	**Recloser/Protection Devices**	Distribution Switchgear	Circuits	All	ID, UT & WY	Infrared Inspection	DSWG	DST-DSWG-120	10	Specific assets on distribution circuit; standing order per area per year. Assets tracked in GIS.	2024
PP	**Underground Vaults**	Vault, Network	All	N/A	OR	Vault Inspection	Plant Locality Number	DST-UGIN-006	6 Months	As recommended by Operations Manager or Asset Management.	
PP	**Underground Vaults**	Vault, Non-Network	All	N/A	OR	Vault Inspection	Plant Locality Number	DST-UGIN-024	2	As recommended by Operations Manager or Asset Management. Change cycle from annual to 2 years, effective 2025.	2025
PP	**Underground Vaults**	Vault, Air Cooled Transformers	All	All	OR	Air-Cooled Transformers Cleaned and Tested	Plant Locality Number	DST-UGTC-084	7		
PP	**Underground Vaults**	n/a	All	N/A	OR	River Crossing Sign Inspection	Plant Locality Number	DST-UGRC-001	monthly	Monthly inspection completed by UG personnel of the river crossing sign, required by City of Portland.	
RMP	**Underground Vaults**	Vault	All	N/A	UT	Vault Inspection	Plant Locality Number	DST-UGIN-006	6 Months	As recommended by Operations Manager or Asset Management.	
RMP	**Underground Vaults**	Vault	All	N/A	UT	Vault Inspection	Plant Locality Number	DST-UGIN-003	3 Months	As recommended by Operations Manager or Asset Management.	
PP & RMP	**FAA Light**	FAA Light	Circuits and Transmission Lines	All	All	FAA Light Inspection	FAAI	XXX-FAAI-012	1	Add only to structures (Trans or Distr) that the Federal Aviation Administration (FAA) has requested a FAA Light be installed. Right of Way will file with the FAA and notify Asset Management of any new FAA equipment requirements.	2025
PP & RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Joslyn or Fisher Pierce	All	Fault Indicator Battery Replacement	FCI	XXX-FIBT-108	9	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Navigator or Unknown	ID, UT & WY	Fault Indicator Battery Replacement	FCI	XXX-FIBT-048	4	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
PP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Navigator or Unknown	CA, OR & WA	Fault Indicator Battery Replacement	FCI	XXX-FIBT-096	8	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
PP & RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	SEL AR360	All	Fault Indicator Unit Replacement	FCI	XXX-FIBT-120	10	Replace Fault Indictor	2024
RMP	**Distribution Capacitors**	Capacitors	Circuits	All	UT & WY	Capacitor Inspection	DCAP	XXX-DCAP-072	6		1/1/2021
PP & RMP	**Transmission High Voltage Switches**	Transmission High Voltage Switches	Transmission Lines	Motor Operator Switches	All	High Voltage Switch Battery Replacement	THVS	XXX-THVS-036	3	Motor operated high voltage switches batteries replaced by Substation Operations. (Task List under SWBT).	

MAINTENANCE INTERVAL LIST
Communications

BU	Equipment Type	Equipment Description	Equipment Use	Equipment Manufacturer or Model	State(s)	Maintenance Task	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**FII SUBSTATION INSPECTIONS**	Field Ops Sub	N/A	N/A	OR	Facility Safety/Operational Inspection	FII-SBIN	XXX-FII-SBIN-001	monthly	Periodic security and operational inspection. **NOTE**: Inspections shall be performed monthly, with no longer than 45 calendar days between consecutive inspections.	
PP	**FII SUBSTATION INSPECTIONS**	Field Ops Sub	N/A	N/A	CA & WA	Facility Safety/Operational Inspection	FII-SBIN	XXX-FII-SBIN-001	monthly	Periodic security and operational inspection. **NOTE:** Company policy requires a minimum of 7 inspections be performed annually, with no more than 120 days between consecutive monthly or 180 days between the more detail major inspections.	
PP & RMP	**Weather Stations**	Weather Stations	Circuits and Transmission Lines	All	All	Inspection, Calibration, Check Battery, and Remove Ground	WEA	XXX-WSIN-012	1	Inspect and clean weather station for damage and calibrate wind, temp, RH and precipitation gages. Check battery and replace if necessary. Remove ground sensor sticks and install a secondary box over ground rod.	Fall 2019

MAINTENANCE INTERVAL LIST
Communications

BU	Equip Code	Equipment Type	Equipment Description	Requires Commissioning (See Note 4)	Equipment Use	Equipment Model Examples	Maintenance Task	Maintenance ID	Interval Calendar Year	Labor Hours	Notes
PP & RMP	**ASR**	Antenna Structure Registration	FCC number attached to a tower and cleared with the FAA	No	Non-BES	Number attached to the tower	Check tower for FCC antenna registration number	GMP6004	4	1	Antenna structure meets FAA and FCC requirements.
PP & RMP	**BAS**	Base Radio	Mobile Radio System Base Station	Yes	Non-BES	TAIT	Testing	GMP6301	1	8	Radio meets FCC requirements.
PP & RMP	**BAS/MCL**	Base Radio Control Link	Point to Point Mobile Radio System	Yes	Non-BES		Testing	GMP6301	2	5	Radio meets FCC requirements.
PP & RMP	**BAT**	Power Supply	Battery & Charger	Yes	Non-BES	All non BES	Inspect & Maintain	GMP6502	1	5	Battery impedance test.
PP & RMP	**BAT**	Lines Cabinet Power Supply	Battery	Yes	Non-BES	All non BES	Inspect & Replace Battery	GMP6003	3	5	Inspect and replace battery. Effective 1/2025
PP & RMP	**BAT**	Substation Site/Vented Lead Acid	Battery & Charger	Yes	BES (WECC)	Alcad, Fiamm, Hoppecke	Battery Inspection	GMP6504	4 month	5	Battery inspection test.
PP & RMP	**BAT**	Substation Site/Valve Regulated	Battery & Charger	Yes	BES (WECC)	East Penn, C&D	Battery Maintenance	GMP6503	4 month	5	Battery impedance test.
PP & RMP	**BAT**	Substation Site/Vented Lead Acid	Battery & Charger	Yes	BES (WECC)	Alcad, Fiamm, Hoppecke	Battery Maintenance	GMP6505	18 month	5	Battery impedance test.
PP & RMP	**DCS**	Digital Cross Connect System	Digital Cross Connect System	Yes	Non-BES	DNX-88, Titan 532L, V4150	Testing	GMP6450	1	3	Verify high speed module protection.
PP & RMP	**EPUy**	Generator (Comm.)	LP Gas Engine Generator	Yes	Non-BES	Generac, Onan, Kohler	Inspect & Maintain	GMP6512	1	6	Pre-winter LOF and inspection.
PP & RMP	**EPUm**	Generator (Comm.)	Diesel generator only	Yes	Non-BES	Caterpillar	Inspect	GMP6513	1 month	1	Monthly startup / inspection. Diesel only.
PP & RMP	**FAC**	Communication Site	Property & Equipment	No	Non-BES	Various	Inspection	GMP6001	6 month	6	Semi-annual check of facility and peripheral equipment.
PP & RMP	**FAC**	Communication Site	Alarms	No	Non-BES	Various	Verification	GMP6006	1	2	Verify alarms on Monarch for PLC and tone relay equipment
PP & RMP	**FOT**	Fiber Optics Terminal	FO Multiplex Equipment	Yes	Non-BES	Larus FT2, ATT DDM 1000, NEC RC28D, DMXplore	Test & Maintain	GMP6402	4	4	Perform tests.
PP & RMP	**DMX FOT**	DMX Fiber Optics Terminal	FO Multiplex Equipment	Yes	Non-BES	DMX, DMXtend	Inspect	GMP6403	1	4	Change filter.
PP & RMP	**MAS**	Radio (MAS) Master All / Transmission only for remotes	SCADA Radio	Yes	Non-BES	Darcomm, MDS, Alligator	Testing	GMP6332	1	4	Perform tests. Radio meets FCC requirements.
PP & RMP	**MAS/MCL**	MAS Radio Control Link	Point to Point SCADA Radio System	Yes	Non-BES	Darcomm, Alligator, Optaphone	Testing	GMP6332	1	4	Perform tests. Radio meets FCC requirements.
PP & RMP	**MWA**	Radio (Analog)	Analog Microwave	Yes	Non-BES	FAS-6000	Testing	GMP6322	1	4	Perform tests on Analog MW.
PP & RMP	**MWD**	Radio (Digital)	Digital Microwave	Yes	Non-BES	Alcatel MDR-6706, Harris Constellation, IRU600	Testing	GMP6312	1	4	Perform tests on Digital MW.
PP & RMP	**OTN**	Optical Transport Network	Fiber	Yes	Non-BES	Ciena 6500	Testing	GMP6405	1	3	Perform tests.
PP & RMP	**PLC**	Power Line Carrier	On/Off PLC Terminal	Yes	BES (WECC)	Westinghouse TC10B	Inspect	GMP6104	4 month	4	Function verification.
PP & RMP	**PLC**	Power Line Carrier	PLC Terminal	Yes	BES (WECC)	GE Type 51, 61, 71, TCF-10B	Maintenance	GMP6102	2 see note 3	7	Check levels & operate. Perform test.
PP & RMP	**RTU**	Remote Terminal Unit/Transmission only	SCADA Remote	Yes	Non-BES, except Jim Bridger SEL RTU's	Harris D-20, L&G 5700	Inspection	GMP6342	1	4	Inspect.
PP & RMP	**RTU**	GE N60	Logic Controller	Yes	CIP	GE N60	Test	GMP6345	5	8	Perform tests.
PP & RMP	**RCC**	Monarch Comm. Channels	SCADA	No	Non-BES	Monarch	Inspection	GMP6343	4 month	3	PCC and SCC communications channel switchover.
PP & RMP	**TON**	Tone Relay	Tone Relay Terminal	Yes	BES (WECC)	GE Type 30, GE Type 40, RFL 6745	Test & Maintain	GMP6202	1 see note 1	5	Check levels & operate. Perform test.
PP & RMP	**TON**	Tone Relay	Tone Relay Terminal	Yes	BES (WECC)	9745	Test & Maintain	GMP6204	4 see note 2	5	Check levels & operate. Perform test.
PP & RMP	**TOWg**	Tower (Guyed)	Tower	Yes	Non-BES	All	Inspecting & Maintain	GMP6005	3	4	Contracted inspection of guyed towers.
PP & RMP	**TOWs**	Tower(Steel)	Tower	Yes	Non-BES	Sabre, Microflect, Valmont	Inspecting & Maintain	GMP6002	5	21	Internal crews inspection of steel towers.

Rocky Mountain Power | Pacific Power

Policy 001

MAINTENANCE INTERVALS FOR APPARATUS, RELAYS, METERS, LINE PATROL/INSPECTIONS, WIRES EQUIPMENT AND COMMUNICATIONS EQUIPMENT

PacifiCorp Asset Maintenance and Compliance Policy 001

Date	Revision #	Notes
…		
12/8/2017	36	Updated maintenance ID for Meters M4, M5 and M6. On Relay tab added new Throwover, Autosource transfer and Air cooled Xfmr maintenance tasks; and removed V1-VBE and S2 maintenance activity. On Apparatus tab added synchronous condenser testing; updated OFIN-xxx; cycle is to be determined; also, updated TNOS-002 added Pacific Power BMMx-036 minor maintenance. On Comm tab modified equipment information.
8/8/2018	37	Updated California Visual Assurance (Patrol) inspections to meet new requirements, corrected Hold Down Inspection policy inspection to Policy 337 from incorrect 377
12/14/2018	38	Line Inspec tab: Updated CA UG detail inspection note; added CA visual inspection to 1 year for Tier 1, 2 & 3; added Fuse Saver. Meter tab: Added CAISO/EIM meter intervals.
5/14/2019	39	Updated Relay Equipment Description for B1_B2 and U1_U2 to include "Monitored and Alarming to Scada", and correcting Maintenance Task for BR2 to "Minor". Correcting CA visual Tier notes.
3/24/2020	40	Maintenance Basis tab added note 3) regarding maintenance cycles less than 1 year. Apparatus tab added new line items for CKB, CAP, TRF and XRT for RMP only Warranty Inspections. Relay tab updated equipment description to "Electromechanical" for B5_B6 maintenance; added BR1 and BR2 to "Montitored alarming to scada" and add new plans BR3 and BR4 for recloser relays "Not Monitored"; also included Sudden Press in BR1, BR3 and BR4 notes. Line tab added Weather station 6 month inspections for RMP. Updated Recloser battery replacment model to 351R2 for RCBT(apc) and DRCL(line). Added FHCA new inspection cycles on Line tab. Added new maintenance activity OTN on Comm tab.
6/21/2021	0-PP	First version of Policy 001 specific to Pacific Power. Updated Communications man hours. Removed WMA maintenance task.
6/20/2022	1-PP	Added local transmission infrared line inspections (wires tab); RAS SPS1 maintenance interval changed from four years to six years (relay tab). Added B1_B2 maintenance to RAS SPS1 maintenance tasks (relay tab). Updated to include distribution breaker overhaul plans for large customers (apparatus tab). Added grid resilience equipment/storage facility inspection and maintenance task (apparatus tab).
6/30/2023	2-PP	Added non-FHCA Transmission Line Infrared Inspections for OR/WA (wires tab, line 15); Added non-NERC remedial action scheme maintenance items (relay tab, line 37 & 41).
10/13/2020	0-RMP	First version of Policy 001 specific to Rocky Mountain Power.
12/22/2020	1-RMP	Revision to update the policy on new transformer baseline DGA cycles.
2/12/2021	2-RMP	Revision to updated the policy on HVAC wall and window units and DGA and WARR on spare transformers; updated DCAP cycle.
9/20/2021	3-RMP	Removed "window" from HVAC maintenance; Combined the DGA on Spare transformers with the Designated/Strategic Spares. Removed MWA and updated TOW hours and notes from Communications tab. Added Synchronous Condenser 5-year & monthly maintenance and 5-year operating validation. Removed 4-month XROS
2/9/2022	4-RMP	Updated maintenance basis explanation for non-WECC apparatus and relay work orders. Added synchronous condenser PRC-019 maintenance requirements. Changed RAS maintenance plan cycle from 4 to 6 years per PRC-005. Added MWA and Alarm GMP plans on Communication tab.
2/9/2023	5-RMP	Updated weather station maintenance plan cycle from 6 months to 1 year. Updated weather station maintenance plan type from EML4 to EML8. Updated cap bank interval from 2 and 4 years to 1 year on GE.
9/18/2023	6-RMP	Added RAS Component maintenance B1_B2; in addition add maintenace for any potential Non-WECC/NERC RAS systems and their components. Removing TNOS specific Plan; noting TROS and XROS plans are to begin 2 months after commissioning. Added DRCL Siemens CMR maintenance. Additional maintennace added for GE SCAP and Sync Condensors. Added STATCOM Maintenance
1/19/2024	7-RMP	Wires tab: Added infrared Inspections to FHCA transmission lines. Added annual inspections on underground transmission lines. Distribution PTT and UG Detail Inspection cycles change from 20-year to 10-year. Adding switchgear infrared inspections. Add SEL AR360 fault indicator unit replacement.
11/4/2024	41	disclaimer. Added Syn Conderson MIN mtc for Goshen. Added PRC-027 Setting requirements, under relay. Separated out Wires Inspections and Equipment into two tabs. DRCL-MAJ added to Wires Equipment tab. Separated out Wires Inspections by State from wires equipment.
5/5/2025	42	Added FAA Inspections on the Wires Equipment tab. Pacific Power UGIN cycle change. Pacific Power CA & WA PTT cycle change to 10yr. WA UG Detail cycle change to 10yr.

MAINTENANCE INTERVAL LIST
Communications

Maintenance Basis

Apparatus	Apparatus maintenance intervals for PacifiCorp are based on a combination of manufacturer's recommendations, failure and corrective maintenance history and experience and the opinions of PacifiCorp subject matter experts. The maintenance intervals are time based, are based on operations counts or based on other triggers.
	The following pertains to apparatus equipment designated as a component of a NERC FAC-501 critical path: 1) Time intervals are developed assuming the required preventative maintenance work will be performed within the calendar year the order is generated with the stated interval being defined as calendar years. 2) For work on equipment that is triggered by an operational counter, the work shall be performed within the calendar year following the counter trigger date. 3) For time intervals less than one year (i.e. 3 months, 4 months, etc.) the preventative maintenance work will be performed within the cycle time period.
	Testing or maintenance activities that call for operation of the equipment may be satisfied if an actual real-time operation of that device can be documented during the last maintenance cycle.
	Maintenance intervals and requirements are reviewed on a periodic basis and adjusted based on failure or maintenance issues, industry trends and manufacturer's recommendations.

Maintenance Deferral for NERC Equipment	Maintenance due in a given calendar year for apparatus equipment designated NERC in Maximo may be deferred if an approved capital replacement project for the equipment is scheduled for the following calendar year or if materials, parts or required expertise are unavailable, delaying work. The maintenance order will be closed when the replaced equipment is placed in-service and a new maintenance plan will be assigned to the replaced equipment. NERC relay maintenance must be completed within caledar year due and cannot be deferred for any NERC in-service equipment.

Maintenance Deferral for Non-NERC Equipment	Work orders and maintenance for non-NERC equipment may be deferred due to operational priorities, approved capital projects or maintenance projects.

Maintenance Actual Finish Dates	Work orders Actual Finish Dates can differentiate from completion date on form due to the new system functionality.

New or Revised Maintenance Policies	Upon creation or revision of a maintenance policy, the determination of when the new maintenance activity will commence on an individual piece of equipment will be determined by PacifiCorp Asset Management. Equipment will not be considered non-compliant with the new or revised maintenance policy interval if the work required per this policy is completed within the calendar year of the initial call date that was assigned to that equipment by PacifiCorp Asset Management.

MAINTENANCE INTERVAL LIST
Communications

Site	Equipment Type	Equipment Description	Equipment Use	Manufacturer	Model Number(s)	Operating Ratings	Maintenance Task	Asset Type	Job Plan ID	Interval Years (Months)	Interval Months	Counters (Ops/Fault)	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Battery**	Vented or NiCad	NERC - Bulk Electrical System	All	All	N/A	Battery Inspection	BATTERY	BTTI	4 Months	4	N/A	Battery inspection.	
PP & RMP	**Battery**	Valve Regulated	NERC - Bulk Electrical System	All	All	N/A	Battery Maintenance	BATTERY	BTTM	4 Months	4	N/A	Battery impedance test.	
PP & RMP	**Battery**	Vented or NiCad	NERC - Bulk Electrical System	All	All	N/A	Battery Maintenance	BATTERY	BTTM	18 Months	18	N/A	Battery impedance test.	
PP & RMP	**Battery**	Vented, NiCad or Valve	Transmission and Distribution (Non-NERC)	All	All	N/A	Battery Maintenance	BATTERY	BTTM	2	24	N/A	Battery impedance test.	
PP & RMP	**Battery**	Sodium Nickel	All	All	All	N/A	N/A	BATTERY	N/A	N/A	N/A	N/A	No maintenance required on these batteries	2024
RMP	**Battery Energy Storage System**	BESS Site		All	All	N/A	Annual Inspection	N/A	BESS	1	12	N/A	Annual inspection of BESS site as indicated on the maintenance form (Panguitch Solar Battery Site).	2020
RMP	**Battery Energy Storage System**	UPS Battery		All	All	N/A	Battery Replacement	BAT_UPS	UPS BATTERY	3	36	N/A	Replace UPS batteries.	2020
RMP	**Battery Energy Storage System**	Fire Suppression System		All	All	N/A	Inspection	FSS	FSS	6 Months	6	N/A	Inspection to be completed by a third party.	2020
RMP	**Battery Energy Storage System**	Solar Panels		All	All	N/A	Infrared Testing by Drone	N/A	SINF-DRONE	1	12	N/A	Infrared testing of solar panels with the use of a drone.	2020
PP & RMP	**Circuit Breakers**	Breaker Battery		All w/UPS	All w/UPS	N/A	Circuit Breaker Battery Replacement	BREAKER	BKBT	3	36	N/A	Circuit breaker battery replacement.	
PP & RMP	**Circuit Breakers**	Recloser Battery		All (except Hydraulic - see Notes column)	All	N/A	Recloser Battery Replacement	RECLOSER	RCBT	3	36	N/A	Recloser battery replacement. Hydraulic reclosers do not have batteries, and do not need maintenance plans.	
PP & RMP	**Circuit Breakers**	Recloser Battery		G&W Viper	with SEL-351R Controllers	N/A	Recloser Battery Replacement	RECLOSER	RCBT	2	24	N/A	Recloser battery replacement.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil		All	All	All Voltages	Warranty Inspection	BREAKER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil	Except Transformer Low Side Circuit Breaker with no Bypass, or 35kV and Below Cap Bank and Others as Approved by Asset Management	All	All	All Voltages	Exercise Breaker	BREAKER OR RECLOSER	BIOA	1	12	N/A	Yearly operational test. May be fulfilled by documentation of an actual operation.	
PP & RMP	**Circuit Breakers**	SF6, Vacuum and Oil	NERC - FAC-501 Critical Path	All	All	All Voltages	Exercise Breaker	BREAKER OR RECLOSER	BIOA	1	12	N/A	Yearly operational test. May be fulfilled by documentation of an actual operation.	
PP & RMP	**Circuit Breakers**	Air	Tertiary Fed Reactor, Cap Bank, Station Service,	All	All	12kV to 34.5kV	Overhaul	BREAKER	BOHA	6	72	N/A		
PP	**Circuit Breakers**	Air	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Minor Maintenance	BREAKER	BMMA	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Air	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Overhaul	BREAKER	BOHA	9	108			

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PP	**Circuit Breakers**	Air	All applications except bus, cap and low side transformer	All	All	35kV and Below	Overhaul	BREAKER	BOHA	0	Counter Based	50-Fault	Counters applied per Asset Management.	
PP	**Circuit Breakers**	SF6 gas	Breakers selected by Pacific Power Asset Management **(LGCU)**	All	All	All Voltages	Minor Maintenance	BREAKER	BMMS	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Capacitor or Reactor Without Zero Crossing Controls	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	8	96		Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Reactor with Zero Crossing Controls	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	6	72	N/A	Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas	Reactor with Zero Crossing Controls	All	All	40kV and Above	Control System Download	BREAKER	BXRT	2	24	N/A	Meter/Relay to download oscillography data and forward to Apparatus Tech Support for review of proper timing. Submit to Asset Management	9/3/2020
RMP	**Circuit Breakers**	SF6 Gas	Capacitors with Zero Crossing Controls	Asea-Brown Boveri	PMI	40kV and Above	Control System Download	BREAKER	BXRT	2	24	N/A	Meter/Relay to download oscillography data and forward to Apparatus Tech Support for review of proper timing. Submit to Asset Management	
PP & RMP	**Circuit Breakers**	SF6 Gas Puffer	Line, Transformer, Bus	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMS	10	120	N/A		
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure	Line, Transformer, Bus	All (except for mfg and models listed below)	All (except for mfg and models listed	40kV and Above	Minor Maintenance	BREAKER	BMMS	4	48	N/A	Time/Ductor inspect mechanism.	
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure		ITE	GA	230kV- 500kV	Overhaul	BREAKER	BOHS	6	72	N/A	These models have overhauls only, no minor maintenance.	
PP & RMP	**Circuit Breakers**	SF6 Gas, Dual Pressure		Westinghouse	2300-SF-15000	230kV	Overhaul	BREAKER	BOHS	6	72	N/A	These models have overhauls only, no minor maintenance.	
PP	**Circuit Breakers**	SF6 Gas, Dual Pressure		Westinghouse	SFA	230kV- 500kV	Overhaul	BREAKER	BOHS	8	96		These models have overhauls only, no minor maintenance.	
PP	**Circuit Breakers**	SF6 gas bottles	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER	BMMS	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	SF6 gas	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER	BOHS	9	108			
PP	**Circuit Breakers**	SF6 gas bottles (sealed module)	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER	BOHS	0	Counter Based	50-Fault	Counters applied per Asset Management. Pacific Power ONLY.	
PP & RMP	**Circuit Breakers**	Oil	Capacitor or Reactor	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMO	6	72			
PP & RMP	**Circuit Breakers**	Oil	Line, Transformer, Bus	All	All	40kV and Above	Minor Maintenance	BREAKER	BMMO	6	72	N/A		
PP	**Circuit Breakers**	Oil	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER	BMMO	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Oil	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER	BOHO	6	72			
PP	**Circuit Breakers**	Oil	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER	BOHO	0	Counter Based	30-Fault	Counters applied per Asset Management.	

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PP & RMP	**Circuit Breakers**	Vacuum	Tertiary Fed Reactor, Cap Bank	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	8	96	N/A		
PP & RMP	**Circuit Breakers**	Vacuum	Tertiary Fed SVC, Wind Site Breakers.	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	10	120	N/A		
PP & RMP	**Circuit Breakers**	Vacuum	Synchronous Condenser	All	All	12kV to 34.5kV	Overhaul	BREAKER OR RECLOSER	BOHV	6	72	N/A		
PP	**Circuit Breakers**	Vacuum	Breakers selected by Pacific Power Asset Management **(LGCU)**				Minor Maintenance	BREAKER OR RECLOSER	BMMV	3	36		Exercise breaker. Inspect, clean and lubricate operating mechanism. Install or relocate cabinet heater as needed.	
PP	**Circuit Breakers**	Vacuum	Breakers selected by Pacific Power Asset Management **(LGCU)**				Overhaul	BREAKER OR RECLOSER	BOHV	9	108			
PP	**Circuit Breakers**	Vacuum	All applications except bus, cap and low side transformer			35kV and below	Overhaul	BREAKER OR RECLOSER	BOHV	0	Counter Based	50-Fault	Counters applied per Asset Management.	
PP & RMP	**Circuit Switcher**	Gas	Reactive Switching, Line Switching or Transformer	S&C Electric Siemens Allis	Type G, Mark Series	100kV or Above	Inspect & Operate	CIRSWR	CSIO	5	60	N/A	Inspect and test.	
PP & RMP	**Circuit Switcher**	Gas	NERC - FAC-501 Critical Path	S&C Electric Siemens Allis	Type G, Mark Series	100kV or Above	Inspect & Operate	CIRSWR	CSIO	5	60	N/A	Inspect and test.	
PP & RMP	**Circuit Switcher**	Gas	No Physical Counter	All	All	All Voltages	Overhaul	CIRSWR	CSOH	8	96	N/A		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric	2000 Series	All Voltages	Overhaul	CIRSWR	CSOH	N/A	Counter Based	3,000-Ops		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric Siemens Allis Southern States	Type G, Mark Series (Mark V - 1984 or newer) Linebacker, CPV2	All Voltages	Overhaul	CIRSWR	CSOH	N/A	N/A	1,500-Ops		
PP & RMP	**Circuit Switcher**	Gas	All Applications	S&C Electric	Mark V - 1983 or older	All Voltages	Overhaul	CIRSWR	CSOH	N/A	N/A	1,000-Ops		
PP & RMP	**Fuse**	All Spare Power Transformer Fuses		S&C Electric SMD Fuses		N/A	Air Flow Test	N/A	FUSE	5	60	N/A	Air flow test.	
PP & RMP	**Generator**	Emergency		All	All	N/A	Annual Inspection	GENERATOR	EPUA	1	12	N/A		
RMP	**Generator**	Mobile	Terminal	All	All	N/A	Start-up & Inspect	GENERATOR	MOGN	Monthly	1	N/A	Monthly start-up and inspection on mobile generators on Barron oil trailers.	
PP	**GRID RESILIENCE STORAGE FACILITY**	Grid resilience facility					GR Equipment/Bldg Inspection	N/A	GRID	4 Months	4	N/A	Inspection of grid resilience equipment and storage facility	
PP & RMP	**HVAC**	Air Conditioning/Heating Systems		All	All	N/A	Inspect & Operate	HVAC	HVAC	1	12	N/A		
RMP	**HVAC**	Wall Units		Bard Mitsubishi	All All	N/A	Inspect & Operate	HVAC	HVAC	1	12	N/A		2021
PP & RMP	**Reactors**	All Types, including Spares	All Applications	All	All	All Voltages	Warranty Inspection	REACTOR	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Reactors**	Oil Filled	All Applications	All	All	All Voltages	DGA & Oil Quality Tests	REACTOR	XROS	1	12	N/A	DGA and oil quality for reactor tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called annully thereafter.	
PP	**Reactors**	Oil Filled		ABB		345kV, 500kV	DGA and Oil Quality Tests	REACTOR	XROS	4 Months	4	N/A	DGA and oil quality for reactor tank. NOTE: Work orders generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	

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PP & RMP	**Regulator LTC**	Vacuum LTC in 3 Phase Regulator		Cooper Power	V2A	N/A	DGA Tests	REGLTC	TCOS	1	12	N/A	DGA for LTC tank.	
PP & RMP	**Regulator LTC**	Non Vacuum with Separate LTC Tank on 3 Phase Regulator		General Electric Cooper Power Westinghouse	MLT32 550BLS and SVR	N/A	DGA Tests	REGLTC	TCOS	4 Months	4	N/A	DGA for LTC tank. NOTE: Work orders are generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Regulator LTC**	3 Phase with Non Vacuum LTC		All	All	All Voltages	Overhaul	REGLTC	RGOH	4	48	N/A	Inspect contacts & filter oil.	
PP & RMP	**Regulator LTC**	3 Phase with Vacuum LTC		Cooper Power	V2A	All Voltages	Overhaul	REGLTC	RGOH	8	96	N/A	Inspect contacts & filter oil.	
PP & RMP	**Regulators**	3 Phase with LTC in Tank		Allis Chalmers General Electric	AFR and SFR TMLT32	All Voltages	DGA & Oil Quality Tests	REGULATOR	RGOS	4 Months	4	N/A	DGA and oil quality for regulator main tank. NOTE: Work orders are generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Regulators**	3 Phase with LTC in Separate Tank		General Electric Cooper Power Westinghouse	MLT32 550BLS and SVR	All Voltages	DGA & Oil Quality Tests	REGULATOR	RGOS	1	12	N/A	DGA and oil quality for a regulator's main tank.	
PP & RMP	**Series Capacitor**	Under 10 years old		All (exclude GE)	All	All Voltages	Inspection	CAPBANK	SCIN	4	48	N/A	On platform equipment	
PP & RMP	**Series Capacitor**	Over 10 years old		All (exclude GE)	All	All Voltages	Inspection	CAPBANK	SCIN	2	24	N/A	On platform equipment	
PP & RMP	**Series Capacitor**	All Years		General Electric	All	All Voltages	Inspection	CAPBANK	SCIN	1 (sequence with SCMT)	12	N/A	On platform equipment	Apr-23
PP & RMP	**Series Capacitor**	All Years		General Electric	All	All Voltages	Maintenance	CAPBANK	SCMT	5 (sequence with SCIN)	60	N/A	On platform equipment	May-23
PP	**Series Capacitor**	With air gap trigger		N/A	N/A	N/A	Air Gap Injection	CAPBANK	ARGP	0	Counter Based	25 Operations	Burns Reactor Sub only	
RMP	**Shunt Capacitor**	All Types		All	All	40kV and Above	Warranty Inspection	CAPBANK	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on the manufacture date. One time only plan.	
PP & RMP	**Spare Equipment**	Strategic Spare Equipment Located in Tech Ops Yard/Bldg.		All	All	All Voltages	Spare Equipment Inspection	N/A	SPAR	4 Months	4	N/A	Inspection of strategic spares in yard.	
RMP	**STATCOM**	Statcom System		All	All	All Voltages	Inspection	N/A	STATCOM-INSP	1 Month	1	N/A	Monthly inspection to be completed 8 times per year; same months as substation	2023
RMP	**STATCOM**	Statcom System		All	All	All Voltages	PM	N/A	STATCOM-PM	1 Year	12	N/A	Annual inspection to be completed by Contractor	2023
RMP	**Substation**	NERC TMIP Facility Pertaining to FAC-501 Critical Path Standard		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically. NOTE: For substations associated with NERC critical paths (FAC-501) a minimum of 10 monthly inspections shall be performed annually, with three of these monthly	
PP	**Substation**	NERC TMIP Facility Pertaining to FAC-501 Critical Path Standard		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN, SBIN-MAJ and SECURITY	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads/minor/major scope performed periodically. NOTE: Substations associated with NERC critical paths (FAC-501), a minimum of 10 monthly inspections shall be performed annually, with 3 of these monthly inspections	

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PP	**Substation**	Substations – Oregon		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN, SBIN-MAJ and SECURITY	Monthly	1	N/A	Periodic substation security and operational inspection, load and counter reads/minor/major scope performed periodically. NOTE: Inspections shall be performed monthly, with no longer than 45 calendar days between consecutive inspections.	
RMP	**Substation**	Non-NERC All Facilities Including Mobiles		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly (8 times per year)	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically.	
PP	**Substation**	Non-NERC All Facilities - California & Washington Including Mobiles		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MIN and SBIN-MAJ	Monthly (8 times per year)	1	N/A	Periodic substation security and operational inspection, load and counter reads / minor / major scope performed periodically.	
RMP	**Substation**	All Pole Mount Sites; Facility with No Electrical Exposure/Fence		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	SBIN-MAJ	1	12	N/A	Inspect pole mounts, collector sites or other facilities with no electrical exposure / fence requirement.	
PP	**Substation**	Pole mount/other facility with no electrical exposure, fence requirement. Excludes FII sites.		N/A	N/A	All Voltages	Facility Safety/Operational Inspection	N/A	OFIN	VARIES	N/A	N/A	Interval determined by Asset Management. Inspect pole mounts, collector sites (4 months) or other facilities with no electrical exposure/fence requirement.	
PP & RMP	**Substation**	Distribution Facility, FII, Pole Mount		N/A	N/A	All Voltages	Infrared Testing	N/A	SINF	2	24	N/A	Infrared testing of substation bus, switches & major equipment.	
PP & RMP	**Substation**	Transmission Facility		N/A	N/A	All Voltages	Infrared Testing	N/A	SINF	1	12	N/A	Infrared testing of substation bus, switches & major equipment.	
PP & RMP	**Substation**	Substation Security System		N/A	N/A	All Voltages	Inspection	N/A	SSS	3	36	N/A	AVTEC contracted to inspect the substation security system. Company required to chaperone AVTEC during the inspection. Compliance identifies security sites.	
PP	**Substation**	Wood Poles		N/A	N/A	All Voltages	Detail, Pole Test & Treat	MISC	WOOD	10	120	N/A	Wood pole within substation fence will be inspected, tested or treated per company's PTT policies. Inspections completed by OSMOSE and coordinated with sub-operations staff.	
RMP	**Synchronous Condenser**	Standpipe Sub		N/A	N/A	N/A	Major Maintenance	CONDENSER	SYNMAJ	5 (sequenced with ANN)	60	N/A	Standpipe Major and Annual maintenance are sequenced.	2024
RMP	**Synchronous Condenser**	Standpipe Sub		N/A	N/A	N/A	Annual Maintenance	CONDENSER	SYNANN	1 (sequenced with MAJ)	12	N/A	Standpipe Major and Annual maintenance are sequenced.	2024
RMP	**Synchronous Condenser**	Goshen Sub		N/A	N/A	N/A	Major Maintenance	CONDENSER	SYNMAJ	5 (sequenced with MIN)	60	N/A		2024
RMP	**Synchronous Condenser**	Goshen Sub		N/A	N/A	N/A	Minor Maintenance	CONDENSER	SYNMIN	5 (sequenced with MAJ)	60	N/A		2024

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RMP	**Synchronous Condenser**	Goshen and Standpipe Subs		N/A	N/A	N/A	Inspection	CONDENSER	SYNMON	Monthly	1	N/A	Monthly Inspection; complete form	2021
RMP	**Synchronous Condenser**	Goshen and Standpipe Subs	NERC	N/A	N/A	N/A	Verify Relay Setting Orders; If Changed, Coordination	CONDENSER	PRC19	5	60	N/A	5 Year Setting Order Verification; If study is required, an EMS3 order will be created; order must be completed within the year	2022
RMP	**Synchronous Condenser**	Goshen and Standpipe Subs	NERC	N/A	N/A	N/A	Verify Operating at Nameplate Capacity	CONDENSER	MOD25	5	60	N/A	5 Year Verification	
PP & RMP	**Synchronous Var Controller (SVC)**	Thyristor Switched		All	All	All Voltages	Inspection/Checkout	SVC	SVCI	2	24	N/A	De-energized inspection/checkout per SVC maintenance checklist.	
PP & RMP	**Tank**	Oil/Fuel Storage Tank		All	All	N/A	Inspection	FTANK or OTANK	TKIN	1	12	N/A	Inspection of oil or fuel storage and trailer mounted tanks.	
PP & RMP	**Tank**	Oil/Fuel Storage Tank, Above Ground		All	All	N/A	Certified Tank Inspection	FTANK or OTANK	TKTS	20	240	N/A	Certified tank inspection performed by STI certified tank inspector per PacifiCorp policy 216 & Steel Tank Institute (STI) document	
PP & RMP	**Tank**	SF6 Cylinder Trailers/Carts		All	All	N/A	Inspection	FTANK or OTANK	SF6C	5	60	N/A	Hammer or ring test SF6 cylinders on handcart and trailers.	
PP & RMP	**Transformer**	1 Phase and 3 Phase		All	All	40kV and Above (High Side)	Warranty Inspection	PTRANSFORMER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	
PP & RMP	**Transformer**	1 Phase	All energized transformers	All	All	Below 230kV (High Side) and 2.5-59 MVA (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	3	36	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called every 36 months thereafter	
PP & RMP	**Transformer**	3 Phase	All energized transformers	All	All	Below 230kV (High Side) and 5-59 MVA (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	3	36	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called every 36 months thereafter	
PP & RMP	**Transformer**	1 or 3-Phase	All energized transformers	All	All	230kV and Above (High Side) or 60 MVA and Above (Top)	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	DGA and oil quality for transformer tank. Initial order to be called 2 months after commissioning of asset to obtain the baseline DGA; orders to be called annully thereafter.	
PP & RMP	**Transformer**	Over 40 years old	All energized transformers	All	All	All Voltages	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	Over 40 years old. DGA and oil quality for transformer tank.	
PP & RMP	**Transformer**	Mobile		All	All	All Voltages	DGA & Oil Quality Tests	PTRANSFORMER	TROS	1	12	N/A	DGA and oil quality for transformer tank.	
PP & RMP	**Transformer**	Non-Energized Spares		All	All	All Voltages	Oil Quality Tests	PTRANSFORMER	TROS	2	24	N/A	Oil quality for transformer tank of non-energized spares.	
PP & RMP	**Transformer**	Spare		All	All	All Voltages	Warranty Inspection	PTRANSFORMER	WARR	4	48	N/A	Inspect equipment for warranty problems. Schedule based on manufacture date. One time only plan.	2021
PP & RMP	**Transformer LTC**	Reactive or Resistive		All	All	N/A	DGA Tests	TRFLTC	TCOS	4 Months	4	N/A	DGA for load tap changer only NOTE: Work orders generated every 4 months, a minimum of 2 tests shall be performed in a calendar year.	
PP & RMP	**Transformer LTC**	Vacuum		Reinhausen Mfg. Cooper Power General Electric	RMV and VR V1 and V2 LRT-200 and	N/A	DGA Tests	TRFLTC	TCOS	1	12	N/A	DGA for load tap changer only.	
PP & RMP	**Transformer LTC**	Reactive With or Without Filter	All Applications and Mobiles	Federal Pacific McGraw Edison	TC-525 and 546 550	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	

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PP & RMP	**Transformer LTC**	Reactive Without Filter	All Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Reactive With Filter	Distribution Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Reactive With Filter	Transmission Applications and Mobiles	Westinghouse Allis Chalmers Maloney McGraw Edison General Electric	UTT, URT and URS TLH-21 MA 496B LRT32	N/A	Overhaul LTC	TRFLTC	TCOH	3	36	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Resistive Without Filter	All Applications and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual	
PP & RMP	**Transformer LTC**	Resistive With Filter	Distribution Applicaton and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	9	108	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual	
PP & RMP	**Transformer LTC**	Resistive With Filter	Transmission Applications and Mobiles	Allis Chalmers Reinhausen	UZD,UZE and UZF TYPE-M or T	N/A	Overhaul LTC	TRFLTC	TCOH	6	72	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Reinhausen Cooper	RMV V1 and V2	N/A	Overhaul LTC	TRFLTC	TCOH	12	144	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual pieces of equipment.	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Reinhausen	VR	N/A	Overhaul LTC	TRFLTC	TCOH	N/A	N/A	300,000 Ops	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual	
PP & RMP	**Transformer LTC**	Vacuum	All Applications and Mobiles	Cooper	LRT-200 and LRT-500	N/A	Overhaul LTC	TRFLTC	TCOH	8	96	N/A	NOTE: Intervals shown are baseline intervals for LTC equipment. Actual intervals may change per maintenance procedures based on analysis performed on the individual	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B2 Equip Code. B2 is scheduled first - 6 years	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	B2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, trip coils if 2 coils present. NOTE: Maintenance shall be scheduled 6 years offset from B1 Equip Code. B2 is scheduled first - 6 years	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B3-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B4 Equip Code. B4 is scheduled first - 6 years	
PP & RMP	**NERC Bulk Electrical System**	Microprocessor Relay Protection System **Not Monitored**	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B4-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B3 Equip Code. B4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B5-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B6 Equip Code. B6 is scheduled first - 6 years	
PP & RMP	**NERC Bulk Electrical System**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B6-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall protection package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B5 Equip Code. B6 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Electronic or Electromechanical Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B7-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B8 Equip Code. B8 is scheduled first - 6 years	
PP & RMP	**NERC Bulk Electrical System**	Electronic or Electromechanical Relay Protection System	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	B8-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall protection package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B7 Equip Code. B8 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Programmable Logic Controller (PLC) Based Protection Systems for Series Capacitor Banks or Other Devices	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	B9-MAJ/CTRL	6	MAJ/CTRL	Test overall protection package, CT/PT's, auxiliary relays, control wiring per procedures, trip coils if 2 present.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 Monitored and Alarming to SCADA	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	BR1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR2 Equip Code. BR2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	BR2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - Maintain non-monitored relays per procedures, trip coils if 2 coils present NOTE: Maintenance shall be scheduled 6 years offset from BR1 Equip Code. BR2 is scheduled first - 6 years after commissioning.	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	BR3-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR2 Equip Code. BR4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	Protection with Reclosing Relay Per PRC-005 **Not Monitored**	Major: Test & Calibrate Relays, Auxiliaries and Verify Inputs	BR4-MAJ	12 (sequenced)	MAJ (INSRVC)	Test overall relay package including sudden press if present, CT/ PT's, auxiliary relays, per procedures, trip coils if 2 coils present and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from BR3 Equip Code. BR4 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Bulk Electrical System**	BES Settings Review PRC-027	Review BES relay settings	PRC-027	6	N/A	P&C Engineer will review settings on BES relay, one year prior to the BES scheduled maintenance.	2025
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	U1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL (INSRVC)	Test overall relay package, CT/ PT's, alarm path, auxiliary relays, control wiring per procedures and verify settings. NOTE: Maintenance shall be scheduled 6 years offset from U2 Equip Code. U2 is scheduled first - 6 years	
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Monitored and Alarming to SCADA**	Minor: Settings, Test Auxiliary's and Verify Inputs	U2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - Maintain non-monitored auxiliary relays per procedures. NOTE: Maintenance shall be scheduled 6 years offset from U1 Equip Code. U2 is scheduled first - 6 years after commissioning.	
PP & RMP	**NERC Under Frequency and Under Voltage**	Microprocessor Relay Protection System **Not Monitored**	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's	U3-MAJ/CTRL	6	MAJ/CTRL (INSRVC)	Test overall relay package, CT/PT's and control wiring.	
PP & RMP	**NERC Under Frequency and Under Voltage**	Electronic or Electromechanical Relay Protection System-Load Shed	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's	U4-MAJ/CTRL	6	MAJ/CTRL (INSRVC)	Test overall relay package, CT/PT's and control wiring.	
PP & RMP	**Transmission (Non-NERC)**	Microprocessor Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T1-MAJ/CTRL	12 (sequenced)	MAJ/CTRL	Functional test overall relay package, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes. NOTE: Maintenance shall be scheduled 6 years offset from T2 Equip Code. T2 is scheduled first - 6 years	
PP & RMP	**Transmission (Non-NERC)**	Microprocessor Relay Protection System	Minor: Settings, Test Auxiliary's and Verify Inputs	T2-MIN	12 (sequenced)	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, NOTE: Maintenance shall be scheduled 6 years offset from T1 Equip Code. T2 is scheduled first - 6 years after commissioning.	
PP & RMP	**Transmission (Non-NERC)**	Primary Microprocessor with Electromechanical or Electronic Backup Relay	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T3-MAJ/CTRL	6	MAJ/CTRL	MP diagnostic, perform relay functional test and element testing of EM/EE relays, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Transmission (Non-NERC)**	Electromechanical or Electronic Relay Protection System	Major & Control: Test & Calibrate Overall Relay Package, Control Circuitry, CT's and PT's and Control Circuitry	T4-MAJ/CTRL	6	MAJ/CTRL	Perform relay functional test and element testing of EM/EE relays, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Transmission (Non-NERC)**	Auto - Throwover	Perform Relay Functional Test and Decouple and Operate Motor Operators	T5-ATOS	6	ATOS	Not subject to PRC-005 standard requirements	

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Site	Equipment Type	Equipment Description	Maintenance Task	Job Plan ID	Interval Years	Procedures	Notes	Policy Effective Date/Year (If Known)
PP & RMP	**Distribution (Non-NERC)**	Microprocessor Relay Protection System	Test & Calibrate Relay Package and Components	D1-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Distribution (Non-NERC)**	Electromechanical or Electronic Relay Protection System	Test & Calibrate Relay Package and Components	D3-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**Distribution (Non-NERC)**	Fuse Protected, Transformer	Test & Calibrate Relays / Devices	D4-CTRL	12	CTRL	Test Thermal / Other Relays	
PP & RMP	**Distribution (Transformer) (Non-NERC)**	Electromechanical or Electronic Relay with Capacitive Components Protection System on Transformer	Test & Calibrate Relay Package and Components	D5-MAJ/CTRL	6	MAJ/CTRL	Perform relay element testing of EM/EE relays / test auxiliary relays. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes.	
PP & RMP	**HMI**	Automated Substation	Replace CPU Battery	S3-HMI	5	N/A	Replace CPU battery.	
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Remedial Action Scheme Functional Testing	SPS1	6	Functional Testing	Maintain per PRC-005-RAS requirements including functional test. Note: If components exist in SPS1 package; B1_B2 maintenace will also be present on all relay packages for the RAS. Only 1 SPS1 plan per RAS, usually the PM is placed on the Substation that the RAS is named after, if not refer	change from 4 yr cycle to 6 yr cyle 1/2022
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Major and Control: test and calibrate overall relay package, control circuitry, CTs, PTs and control circuitry	B1-MAJ/CTRL	12	MAJ/CTRL (INSRVC)	Test overall relay package including sudden pressure if present, CT/ PTs, alarm path, auxiliary relays, control wiring per procedures, trip coils if 2 coils present, verify settings. NOTE: Maintenance shall be scheduled 6 years offset from B2 Equip Code. B2 is scheduled first, 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**NERC REMEDIAL ACTION SCHEME**	Remedial Action System Components	Minor: settings, test auxiliaries, verify inputs	B2-MIN	12	MIN	Verify inputs and settings, download history. Maintain non-monitored relays per procedures, trip coils if 2 coils present. NOTE: Maintenance shall be scheduled 6 years offset from B1 Equip Code. B2 is scheduled first, 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Remedial Action Scheme Functional Testing	SPSN	6	Functional Testing	Maintain per PRC-005 requirements including functional test. Note: If components exist in SPSN package; T1_T2 maintenace will also be present on all realy packages	3/2023 Added to cover Non-WECC/NERC RAS Systems
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Major and control: test and calibrate overall relay package, control circuitry, CTs and PTs and control circuitry	T1-MAJ/CTRL	12	MAJ/CTRL	Functional test overall relay package, operate lockouts if feasible. NOTE: See maintenance procedures for detailed control circuitry testing and auxiliary relay testing requirements for individual equipment codes. NOTE: Maintenance shall be scheduled 6 years offset from T2 Equip Code. T2 is scheduled first - 6 years	3/2023 Added to cover Components only installed for protection of the RAS
PP & RMP	**REMEDIAL ACTION SCHEME (NON-NERC)**	Remedial Action System Components	Minor: A/D, settings, auxiliaries	T2-MIN	12	MIN	Verify inputs and settings, download history - maintain non-monitored relays per procedures, NOTE: Maintenance shall be scheduled 6 years offset from T1 Equip Code. T2 is scheduled first - 6 years after commissioning.	3/2023 Added to cover Components only installed for protection of
PP	**Relay - Doble Test Equip**	Doble F6150 test equipment	Test and calibrate relay test set	TEST	1	N/A	Perform annual calibration of Doble F6150	

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Site	Equipment	Equipment Types	Equipment Use	Witness	Form(s) to Submit	Interval Years	Job Plan ID	Notes	Policy Effective Date/Year (if known)
PP & RMP	**Meter Package**	Intertie Meters (Interchange Meter as Defined by NERC BAL-005)	PAC-Owned NERC	YES	Form 129F	2	M1-MTR or M1-REL	Test Document 129F must have the NERC/WECC portion populated on at least one	
PP & RMP	**Meter Package**	Intertie Meters (Interchange Meter as Defined by NERC BAL-005)	Foreign-Owned	YES	Foreign Utility Test Form & Form 130F	Varies	M2-MTR or M2-REL	Interval determined by other utility.	
PP & RMP	**Meter Package**	Borderline or PAC Gen Meters	PAC-Owned Non-NERC	YES	Form 129F	2	M3-MTR or M3-REL		
PP & RMP	**Meter Package**	Borderline or Cust Gen Meters	Foreign-Owned Non-NERC	YES	Foreign Utility Test Form & Form 130F	Varies	M4-MTR or M4-REL	Interval determined by other utility.	
PP & RMP	**Meter Package**	Borderline, Gen Retail, PAC Gen or Load Meters	PAC-Owned Non-NERC	NO	Form 129F	2	M5-MTR or M5-REL	Load - Meters used for retail loads that provide SCADA to the EMS	
PP & RMP	**Meter Package**	Check or Stateline Meters	PAC-Owned Non-NERC	NO	Form 129F	5	M6-MTR or M6-REL		
PP & RMP	**Meter Package**	Retail	PAC-Owned Non-NERC	NO	None	Varies	Maintained in CSS	Retail - Meter used for retail load outside of a substation.	
PP & RMP	**Meter Package**	CAISO/EIM Meters	PAC-Owned	NO	Form 129F	2	Various		
PP & RMP	**Meter Package**	CAISO/EIM Meters	Foreign-Owned	YES	Foreign Utility Test Form & Form 130F	2	Various		

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1	NOTE: CA PUC maximum interval is 2 years plus 3 calendar months from the previous inspection for Non-Tier and Tier 1 areas. Change from 2 year cycle to 1 year cycle (effective 1/1/2025)	2025
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	NOTE: CA PUC maximum interval is 5 years plus 3 calendar months from the previous detail inspection. Note: Detail is combined with PTT on PTT years	n/
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If detail and PTT are combined in one task, per CA PUC the combined inspection must be performed no later than 5 years and 3 months from the previous detail inspection. Maximum interval between PTT inspection is 20 calendar years. Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1	NOTE: CA PUC maximum interval is 1 year plus 3 calendar months from the previous inspection for Tier 2 and Tier 3 areas in CA. *** Tier 3 must have at least one (1) inspection completed by June 30th. FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2019
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	NOTE: CA PUC maximum interval is 5 years plus 3 calendar months from the previous detail inspection. *** Tier 3 must have at least one (1) inspection completed by June 30th. Note: Detail is combined with PTT on PTT years FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2019
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA; Tier 2/3	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If detail and PTT are combined in one task, per CA PUC the combined inspection must be performed no later than 5 years and 3 months from the previous detail inspection. Maximum interval between PTT inspection is 20 calendar years. *** Tier 3 must have at least one (1) inspection completed by June 30th. Cycle change from 20 year to 10 year, effective in 2026. FHCA Tier 2/3 must have at least one (1) inspection completed by June 30th, effective in 2026.	2026
PP	**Distribution Circuit**	Underground Distribution Circuit	All	CA	Visual Assurance Inspection (V)	V-D-V-D	Map String	Standing Order	2	NOTE: CA PUC maximum interval is 2 years plus 3 calendar months from the previous inspection.	n/
PP	**Distribution Circuit**	Underground Distribution Circuit	All	CA	Detail Inspection (D)	D-V-D-V	Map String	Standing Order	4	Cabinets shall be opened and visually inspected (CA and OR only) Note: CA PUC maximum interval is 5 years plus 3 calendar months from previous inspection.	n/
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10		n/
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1		2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	NOTE: If Detail and PTT are combined in one task, the combined inspection must be performed no later than 5 years. Maximum interval between PTT inspection is 10 calendar years. Note: Detail and PTT is combined on PTT years	2020
PP	**Distribution Circuit**	Underground Distribution Circuit	All	OR	Detail Inspection (D)	n/a	Map String	Standing Order	10	Cabinets shall be opened and visually inspected (CA and OR only)	n/
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
~~**PP**~~	~~**Distribution Circuit**~~	~~Overhead Distribution Circuit~~	~~Non-FHCA~~	~~WA~~	~~Detail Inspection (D)~~	~~D&V-V-V-V-V-V-V-V-V-PTT-V-V-V-V-V-V-V-V-V~~	~~Map String~~	~~Standing Order~~	~~10~~	~~Note: Detail is combined with PTT on PTT years~~ Due PTT cycle increase to 10 year; stand alone detail inspections will be removed, effective 2026	~~2021~~
PP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-D&V-V-V-V-V-PTT	Map String	Standing Order	1		2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
PP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years Cycle change from 20 year to 10 year, effective in 2026.	2026
PP	**Distribution Circuit**	Underground Distribution Circuit	All	WA	Detail Inspection (D)	n/a	Map String	Standing Order	10	Cycle change from 20 year to 10 year, effective in 2026.	2026
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	ID	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	ID	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-D-V-V-V-V-PTT&V	Map String	Standing Order	1		2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Detail Inspection (D)	D-V-V-V-V-PTT&V-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	UT	Detail Pole Test and Treat (PTT)	PTT&V-V-V-V-V-D=--V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years.	2020
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	UT	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Map String	Standing Order	1	Change from 2 year cycle to 1 year cycle (effective 1/1/2025).	2025
RMP	**Distribution Circuit**	Overhead Distribution Circuit	Non-FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-D-V-V-V-V-PTT&V	Map String	Standing Order	1		2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Detail Inspection (D)	D-V-V-V-V-PTT&V-V-V-V-V	Map String	Standing Order	5	Note: Detail is combined with PTT on PTT years	2020
RMP	**Distribution Circuit**	Overhead Distribution Circuit	FHCA	WY	Detail Pole Test and Treat (PTT)	PTT&V-V-V-V-V-D=--V-V-V	Map String	Standing Order	10	Note: Detail and PTT is combined on PTT years.	2020
RMP	**Distribution Circuit**	Underground Distribution Circuit	All	WY	Detail Inspection (D)	n/a	Map String	Standing Order	10	Changed from 20 year cycle to 10 year (effective 1/1/2024).	2024
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1		1/1/2
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		1/1/2
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	1/1/2
PP	**Local Transmission Line**	Overhead transmission line	All	CA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	1/1/2
PP	**Local Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/2
PP	**Local Transmission Line**	Overhead transmission line	Glass ONLY Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	1/1/2
PP	**Local Transmission Line**	Overhead transmission line	FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1		1/1/2
PP	**Local Transmission Line**	Overhead transmission line	Non-FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	LOC-IR-024	2		1/1/2

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	Local Transmission Line	Overhead transmission line	Non-FHCA	OR	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
PP	Local Transmission Line	Overhead transmission line	Non-FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	OR	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	OR	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	OR	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	1/1/2
PP	Local Transmission Line	Overhead transmission line	Polymer & Glass Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/2
PP	Local Transmission Line	Overhead transmission line	Glass ONLY Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR FHCA	1	Note: As of 2024 there are no FHCA areas identified in Washington	1/1/2
PP	Local Transmission Line	Overhead transmission line	Non-FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	LOC-IR-024	2		1/1/2
PP	Local Transmission Line	Overhead transmission line	Non-FHCA	WA	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
PP	Local Transmission Line	Overhead transmission line	Non-FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	WA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1	Note: As of 2024 there are no FHCA areas identified in Washington	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	WA	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: As of 2024 there are no FHCA areas identified in Washington Note: Sequenced with PTT Note: Detai is combined with PTT on PTT years	1/1/2
PP	Local Transmission Line	Overhead transmission line	FHCA	WA	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: As of 2024 there are no FHCA areas identified in Washington Note: Sequenced with Detail	1/1/2
PP	Local Transmission Line	Overhead transmission line	Polymer & Glass Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/2
PP	Local Transmission Line	Overhead transmission line	Glass ONLY Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	LOC-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction	1/1/2
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	ID	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	1/1/2
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	ID	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1	Note: As of 2024 there are no FHCA areas identified in Idaho	2024
PP	Local Transmission Line	Overhead transmission line	FHCA	ID	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1	Note: As of 2024 there are no FHCA areas identified in Idaho	1/1/2

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PP	Local Transmission Line	Overhead transmission line	FHCA	ID	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: As of 2024 there are no FHCA areas identified in Idaho Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	1/1/
PP	Local Transmission Line	Overhead transmission line	FHCA	ID	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: As of 2024 there are no FHCA areas identified in Idaho Note: Sequenced with Detail	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	UT	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	UT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		2020
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	UT	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	UT	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	UT	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1		2024
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	WY	Visual Assurance Inspection (V)	V-V-V-V-V-V-V-V-V-PTT	Plant Locality Number	LOC-ISA	1	All Local Transmission Lines now on annual cycle, beginning 2025 Note: Sequenced with PTT	2025
RMP	Local Transmission Line	Overhead Transmission Line	Non-FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Visual	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	WY	Visual Assurance Inspection (V)	n/a	Plant Locality Number	LOC-ISA	1		2020
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	WY	Detail Inspection (D)	D&V-V-V-V-V-PTT-V-V-V-V	Plant Locality Number	LOC-IFA	5	Note: Sequenced with PTT Note: Detail is combined with PTT on PTT years	2020
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	WY	Detail Pole Test and Treat (PTT)	PTT-V-V-V-V-D&V-V-V-V-V	Plant Locality Number	LOC-PTT	10	Note: Sequenced with Detail	1/1/
RMP	Local Transmission Line	Overhead Transmission Line	FHCA	WY	Infrared Inspection	n/a	Plant Locality Number	LOC-IRFHCA	1		2024
RMP	Local Transmission Line	Underground Transmission Line	All	UT	Detail Inspection	n/a	Plant Locality Number	LOC-UGIN-003	3 Months	Inspection is only on one UG transmission line PL#071003.	
RMP	Local Transmission Line	Underground Transmission Line	All	UT	Major Detail Inspection (MAJ)	MAJ-MIN-MAJ-MIN	Plant Locality Number	LOC-UGIN-MAJ	2	Inspection done on specific lines, which have UG points, by UG crews. NOTE: Maintenance shall be scheduled 2 years offset from Minor Detail Inspection. Minor is scheduled first.	2024
RMP	Local Transmission Line	Underground Transmission Line	All	UT	Minor Detail Inspection (MIN)	MIN-MAJ-MIN-MAJ	Plant Locality Number	LOC-UGIN-MIN	2	Inspection done on specific lines, which have UG points, by UG crews. NOTE: Maintenance shall be scheduled 2 years offset from Major Detail Inspection. Minor is scheduled first.	2024
PP	Main Grid Transmission Line	Overhead transmission line	All	CA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
PP	Main Grid Transmission Line	Overhead transmission line	All	CA	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
PP	Main Grid Transmission Line	Overhead transmission line	All	CA	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
PP	Main Grid Transmission Line	Overhead Transmission Line	All	CA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		1/1/
PP	Main Grid Transmission Line	Overhead transmission line	Polymer & Glass Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/
PP	Main Grid Transmission Line	Overhead transmission line	Glass ONLY Insulators	CA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	1/1/

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PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	All	OR	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
PP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		1/1/
PP	**Main Grid Transmission Line**	Overhead Transmission Line	Non-FHCA	OR	Infrared Inspection	n/a	Plant Locality Number	MGT-IR-024	2		1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	Glass ONLY Insulators	OR	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	All	WA	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
PP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR FHCA	1		1/1/
PP	**Main Grid Transmission Line**	Overhead Transmission Line	Non-FHCA	WA	Infrared Inspection	n/a	Plant Locality Number	MGT-IR-024	2		1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	Polymer & Glass Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-012	1	Inspect per Policy 337. Interval annual on hold down structures utilizing polymer and glass insulators in their construction.	1/1/
PP	**Main Grid Transmission Line**	Overhead transmission line	Glass ONLY Insulators	WA	Hold Down Inspection	n/a	Plant Locality Number	MGT-HOLD-024	2	Inspect per Policy 337. Interval every two years on hold down structures utilizing glass ONLY insulators in their construction.	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	AZ	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	AZ	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Arizona	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	CO	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	CO	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Colorado	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	ID	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	ID	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Idaho	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	MT	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	MT	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in Montana	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	NM	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	NM	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1	Note: As of 2024 there are no FHCA areas in New Mexico	2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	UT	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/

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BU	Equipment Type	Equipment Description	Equipment Use	State(s)	Maintenance Task	CURRENT Sequenced Maintenance (example)	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	UT	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1		2024
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Visual Assurance Inspection (V)	n/a	Plant Locality Number	MGT-AIR	1		1/1/2
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Detail Inspection (D)	D-D-D-D-D-PTT	Plant Locality Number	MGT-PAT	2	Note: Sequenced with PTT	1/1/2
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	All	WY	Detail Pole Test and Treat (PTT)	PTT-D-D-D-D-D	Plant Locality Number	MGT-PTT	10	Note: Sequenced with Detail	1/1/2
RMP	**Main Grid Transmission Line**	Overhead Transmission Line	FHCA	WY	Infrared Inspection	n/a	Plant Locality Number	MGT-IRFHCA	1		2024

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BU	Equipment Type	Equipment Description	Equipment Use	Equipment Manufacturer or Model	State(s)	Maintenance Task	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP & RMP	**Recloser/Protection Devices**	Distribution Transfer Switch U/G	All	All	All	Operate MO	DTSW	DST-DTSW-060	5	Work coordinated by Wires.	
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	All (excluding G&W Viper w/SEL-351R Controllers)	All	Recloser Battery Replacement	DRCL	DST-DRCL-MIN-036	3	Line reclosers maintained by Substation Operations. Note: Sequenced with DRCL-MAJ PM Note: PP PM descriptions will not be updated until 2026; PP will continue to create PMs as DST-DRCL-036 stand alone.	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	G&W Viper with SEL-351R Controllers	All	Recloser Battery Replacement	DRCL	DST-DRCL-MIN-024	2	Line reclosers maintained by Substation Operations. Note: Sequenced with DRCL-MAJ PM Note: PP PM descriptions will not be updated until 2026; PP will continue to create PMs as DST-DRCL-024 stand alone.	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	All	All	Recloser Settings	DRCL	DST-DRCL-MAJ-072	6	Settings downloaded for review by Tech Ops and replace battery. Note: Sequenced with DRCL-MIN 2 year and 3 year PMs	2025-RMP 2026-PP
PP & RMP	**Recloser/Protection Devices**	Distribution Recloser Controller	Circuits	Siemens CMR	All	Recloser Battery Replacement	DRCL	DST-DRCL-120	10	Line reclosers maintained by Substation Operations.	2023
PP & RMP	**Recloser/Protection Devices**	Distribution Fuse Saver	Circuits	All	All	Battery Replacement	FSV	DST-FSBT-060	5	Work coordinated by Wires.	
RMP	**Recloser/Protection Devices**	Distribution Switchgear	Circuits	All	ID, UT & WY	Infrared Inspection	DSWG	DST-DSWG-120	10	Specific assets on distribution circuit; standing order per area per year. Assets tracked in GIS.	2024
PP	**Underground Vaults**	Vault, Network	All	N/A	OR	Vault Inspection	Plant Locality Number	DST-UGIN-006	6 Months	As recommended by Operations Manager or Asset Management.	
PP	**Underground Vaults**	Vault, Non-Network	All	N/A	OR	Vault Inspection	Plant Locality Number	DST-UGIN-024	2	As recommended by Operations Manager or Asset Management. Change cycle from annual to 2 years, effective 2025.	2025
PP	**Underground Vaults**	Vault, Air Cooled Transformers	All	All	OR	Air-Cooled Transformers Cleaned and Tested	Plant Locality Number	DST-UGTC-084	7		
PP	**Underground Vaults**	n/a	All	N/A	OR	River Crossing Sign Inspection	Plant Locality Number	DST-UGRC-001	monthly	Monthly inspection completed by UG personnel of the river crossing sign, required by City of Portland.	
RMP	**Underground Vaults**	Vault	All	N/A	UT	Vault Inspection	Plant Locality Number	DST-UGIN-006	6 Months	As recommended by Operations Manager or Asset Management.	
RMP	**Underground Vaults**	Vault	All	N/A	UT	Vault Inspection	Plant Locality Number	DST-UGIN-003	3 Months	As recommended by Operations Manager or Asset Management.	
PP & RMP	**FAA Light**	FAA Light	Circuits and Transmission Lines	All	All	FAA Light Inspection	FAAI	XXX-FAAI-012	1	Add only to structures (Trans or Distr) that the Federal Aviation Administration (FAA) has requested a FAA Light be installed. Right of Way will file with the FAA and notify Asset Management of any new FAA equipment requirements.	2025
PP & RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Joslyn or Fisher Pierce	All	Fault Indicator Battery Replacement	FCI	XXX-FIBT-108	9	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Navigator or Unknown	ID, UT & WY	Fault Indicator Battery Replacement	FCI	XXX-FIBT-048	4	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
PP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	Navigator or Unknown	CA, OR & WA	Fault Indicator Battery Replacement	FCI	XXX-FIBT-096	8	Add to only Overhead Fault Indicators; excluding Underground and Communicating Fault Indicators.	
PP & RMP	**Fault Indicators**	Fault Indicators	Circuits and Transmission Lines	SEL AR360	All	Fault Indicator Unit Replacement	FCI	XXX-FIBT-120	10	Replace Fault Indictor	2024
RMP	**Distribution Capacitors**	Capacitors	Circuits	All	UT & WY	Capacitor Inspection	DCAP	XXX-DCAP-072	6		1/1/2021
PP & RMP	**Transmission High Voltage Switches**	Transmission High Voltage Switches	Transmission Lines	Motor Operator Switches	All	High Voltage Switch Battery Replacement	THVS	XXX-THVS-036	3	Motor operated high voltage switches batteries replaced by Substation Operations. (Task List under SWBT).	
PP	**FII SUBSTATION INSPECTIONS**	Field Ops Sub	N/A	N/A	OR	Facility Safety/Operational Inspection	FII-SBIN	XXX-FII-SBIN-001	monthly	Periodic security and operational inspection. **NOTE**: Inspections shall be performed monthly, with no longer than 45 calendar days between consecutive inspections.	

MAINTENANCE INTERVAL LIST
Communications

BU	Equipment Type	Equipment Description	Equipment Use	Equipment Manufacturer or Model	State(s)	Maintenance Task	Equipment Code (Tech ID)	Maintenance ID (XXX = DST, LOC or MGT)	Interval Calendar Year	Notes	Policy Effective Date/Year (if known)
PP	**FII SUBSTATION INSPECTIONS**	Field Ops Sub	N/A	N/A	CA & WA	Facility Safety/Operational Inspection	FII-SBIN	XXX-FII-SBIN-001	monthly	Periodic security and operational inspection. **NOTE:** Company policy requires a minimum of 7 inspections be performed annually, with no more than 120 days between consecutive monthly or 180 days between the more detail major inspections	
PP & RMP	**Weather Stations**	Weather Stations	Circuits and Transmission Lines	All	All	Inspection, Calibration, Check Battery, and Remove	WEA	XXX-WSIN-012	1	Inspect and clean weather station for damage and calibrate wind, temp, RH and precipitation gages. Check battery and replace if necessary. Remove ground sensor sticks and install a secondary	Fall 2019

MAINTENANCE INTERVAL LIST
Communications

BU	Equip Code	Equipment Type	Equipment Description	Requires Commissioning (See Note 4)	Equipment Use	Equipment Model Examples	Maintenance Task	Maintenance ID	Interval Calendar Year	Labor Hours	Notes
PP & RMP	**ASR**	Antenna Structure Registration	FCC number attached to a tower and cleared with the FAA	No	Non-BES	Number attached to the tower	Check tower for FCC antenna registration number	GMP6004	4	1	Antenna structure meets FAA and FCC requirements.
PP & RMP	**BAS**	Base Radio	Mobile Radio System Base Station	Yes	Non-BES	TAIT	Testing	GMP6301	1	8	Radio meets FCC requirements.
PP & RMP	**BAS/MCL**	Base Radio Control Link	Point to Point Mobile Radio System	Yes	Non-BES		Testing	GMP6301	2	5	Radio meets FCC requirements.
PP & RMP	**BAT**	Power Supply	Battery & Charger	Yes	Non-BES	All non BES	Inspect & Maintain	GMP6502	1	5	Battery impedance test.
PP & RMP	**BAT**	Lines Cabinet Power Supply	Battery	Yes	Non-BES	All non BES	Inspect & Replace Battery	GMP6003	3	5	Inspect and replace battery. Effective 1/2025
PP & RMP	**BAT**	Substation Site/Vented Lead Acid	Battery & Charger	Yes	BES (WECC)	Alcad, Fiamm, Hoppecke	Battery Inspection	GMP6504	4 month	5	Battery inspection test.
PP & RMP	**BAT**	Substation Site/Valve Regulated	Battery & Charger	Yes	BES (WECC)	East Penn, C&D	Battery Maintenance	GMP6503	4 month	5	Battery impedance test.
PP & RMP	**BAT**	Substation Site/Vented Lead Acid	Battery & Charger	Yes	BES (WECC)	Alcad, Fiamm, Hoppecke	Battery Maintenance	GMP6505	18 month	5	Battery impedance test.
PP & RMP	**DCS**	Digital Cross Connect System	Digital Cross Connect System	Yes	Non-BES	DNX-88, Titan 532L, V4150	Testing	GMP6450	1	3	Verify high speed module protection.
PP & RMP	**EPUy**	Generator (Comm.)	LP Gas Engine Generator	Yes	Non-BES	Generac, Onan, Kohler	Inspect & Maintain	GMP6512	1	6	Pre-winter LOF and inspection.
PP & RMP	**EPUm**	Generator (Comm.)	Diesel generator only	Yes	Non-BES	Caterpillar	Inspect	GMP6513	1 month	1	Monthly startup / inspection. Diesel only.
PP & RMP	**FAC**	Communication Site	Property & Equipment	No	Non-BES	Various	Inspection	GMP6001	6 month	6	Semi-annual check of facility and peripheral equipment.
PP & RMP	**FAC**	Communication Site	Alarms	No	Non-BES	Various	Verification	GMP6006	1	2	Verify alarms on Monarch for PLC and tone relay equipment
PP & RMP	**FOT**	Fiber Optics Terminal	FO Multiplex Equipment	Yes	Non-BES	Larus FT2, ATT DDM 1000, NEC RC28D, DMXplore	Test & Maintain	GMP6402	4	4	Perform tests.
PP & RMP	**DMX FOT**	DMX Fiber Optics Terminal	FO Multiplex Equipment	Yes	Non-BES	DMX, DMXtend	Inspect	GMP6403	1	4	Change filter.
PP & RMP	**MAS**	Radio (MAS) Master All / Transmission only for remotes	SCADA Radio	Yes	Non-BES	Darcomm, MDS, Alligator	Testing	GMP6332	1	4	Perform tests. Radio meets FCC requirements.
PP & RMP	**MAS/MCL**	MAS Radio Control Link	Point to Point SCADA Radio System	Yes	Non-BES	Darcomm, Alligator, Optaphone	Testing	GMP6332	1	4	Perform tests. Radio meets FCC requirements.
PP & RMP	**MWA**	Radio (Analog)	Analog Microwave	Yes	Non-BES	FAS-6000	Testing	GMP6322	1	4	Perform tests on Analog MW.
PP & RMP	**MWD**	Radio (Digital)	Digital Microwave	Yes	Non-BES	Alcatel MDR-6706, Harris Constellation, IRU600	Testing	GMP6312	1	4	Perform tests on Digital MW.
PP & RMP	**OTN**	Optical Transport Network	Fiber	Yes	Non-BES	Ciena 6500	Testing	GMP6405	1	3	Perform tests.
PP & RMP	**PLC**	Power Line Carrier	On/Off PLC Terminal	Yes	BES (WECC)	Westinghouse TC10B	Inspect	GMP6104	4 month	4	Function verification.
PP & RMP	**PLC**	Power Line Carrier	PLC Terminal	Yes	BES (WECC)	GE Type 51, 61, 71, TCF-10B	Maintenance	GMP6102	2 see note 3	7	Check levels & operate. Perform test.
PP & RMP	**RTU**	Remote Terminal Unit/Transmission only	SCADA Remote	Yes	Non-BES, except Jim Bridger SEL RTU's	Harris D-20, L&G 5700	Inspection	GMP6342	1	4	Inspect.
PP & RMP	**RTU**	GE N60	Logic Controller	Yes	CIP	GE N60	Test	GMP6345	5	8	Perform tests.
PP & RMP	**RCC**	Monarch Comm. Channels	SCADA	No	Non-BES	Monarch	Inspection	GMP6343	4 month	3	PCC and SCC communications channel switchover.
PP & RMP	**TON**	Tone Relay	Tone Relay Terminal	Yes	BES (WECC)	GE Type 30, GE Type 40, RFL 6745	Test & Maintain	GMP6202	1 see note 1	5	Check levels & operate. Perform test.
PP & RMP	**TON**	Tone Relay	Tone Relay Terminal	Yes	BES (WECC)	9745	Test & Maintain	GMP6204	4 see note 2	5	Check levels & operate. Perform test.
PP & RMP	**TOWg**	Tower (Guyed)	Tower	Yes	Non-BES	All	Inspecting & Maintain	GMP6005	3	4	Contracted inspection of guyed towers.
PP & RMP	**TOWs**	Tower(Steel)	Tower	Yes	Non-BES	Sabre, Microflect, Valmont	Inspecting & Maintain	GMP6002	5	21	Internal crews inspection of steel towers

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Pacific Power |
Rocky Mountain Power
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Portland, Oregon 97232

Exhibit M.07
Performance Based Requirements for Pacific Power
DETAILED INSPECTIONS and DETAILED TEST and TREAT ACTIVITY

Reference: Exhibit A.01 Scope of Work – Inspect, Wood Pole and Treat

The following performance-based requirements will apply to all Work performed in the **Pacific Power** service territory of the Company:

1. All Oregon and Washigntion "Detailed Inspections" or "Detailed Test & Treat" work will be completed to a degree of accuracy at or above 90% in urban areas and 80% in rural areas, as measured by the Pacific Power field inspection audit program. In California, the requirement is 95% in urban and rural areas. Areas which are audited by Pacific Power and found to be below the required accuracy rating will be re-inspected by Contractor to assure that the accuracy requirement has been achieved. Contractor will be responsible for all costs of any re-inspection activities that are required, and will not invoice such re-inspection costs to the Company.
2. Contractor will be expected to provide the detailed results from the Contractor audit program of Pacific Power facilities within five (5) business days of completion of the audit in a format that will afford the Company the ability to consistently monitor and report performance from both the Pacific Power and Contractor audits. Additionally, the Contractor audit program will be open for audit upon request by the Company.
3. The Company will work in partnership with Contractor in interpretation of field conditions and special training needs; Contractor is expected to provide their own qualified training and quality control resources. Those resources will be subject to review by the Company, readily accessible and of sufficient quality to ensure a self-sustaining training and quality assurance program that meets performance requirements. The Company will require access to training and quality control program information and results to validate the program’s effectiveness and suitability.
4. The Company inspection quality validation audits will be performed within 60 days of Contractor completing inspection in an area. Contractor will be notified of those results within the required timeframe. Any deficiencies requiring re-inspection or correction of work will be completed within 60 days of notification. Upon completion of these re-inspections or correction of other work, Contractor will immediately notify the affected Inspection Support manager or supervisor so that the area may be re-audited.
5. Contractor will be expected to have a management representative readily available in the general area of the Company's service territory capable of dealing with any issues that need immediate attention. Any communications or decisions involving scheduling, manpower changes, customer issues, work plan or other emerging conditions will be communicated to the affected Field Inspection Support Manager as conditions become known and before any changes are made.
6. During the term of the contract, and any extensions, contractor will submit timely and accurate invoices as soon as practical upon completion of the work using the invoice exhibit and contract docuemtn requirements. The Company will insure timely payment in accordance with the requirements of the contract.

Note: Performance requirements are subject to change as the business need arises.

Policy

Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk

Power Delivery Policy PAC-1000

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Affected Departments:	Power Delivery	
Effective Date:	04/28/2025	

Policy

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Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk

Power Delivery Policy PAC-1000

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1. SCOPE

PacifiCorp has comprehensive plans for wildfire mitigation efforts designed to reduce the probability of utility related wildfire ignition and to mitigate damage to company assets. This policy addresses the company's cross-departmental approach to monitoring asset health, meteorological and fuel conditions related to wildfire risk and adjusting daily operations of transmission and distribution system assets, including network restoration, and fire encroachment during identified periods of elevated wildfire risk.

2. REFERENCES

SOP-010	Wildfire Risk De-Energization Review Procedure
SOP-200	Operating Bulk Electric System Assets During Identified Wildfire Risk Procedure
SOP-201	Operating Sub-transmission Assets During Identified Wildfire Risk Procedure
SOP-202	Operating Distribution Assets During Identified Wildfire Risk Procedure
SOP-203	Wildfire Encroachment Procedure
SOP-204	Emergency De-energization Request Procedure
2D.1	Relay Setting Guide
MET-100	Meteorology Wildfire Risk Modeling Procedure
	Public Safety Power Shutoff Playbook

3. DEFINITIONS

Emergency Coordination Center (ECC) – Is a cross departmental group activated when conditions warrant and led by the ECC Executive. During periods of extreme wildfire risk, the ECC monitors the electrical network and evolving weather conditions, both actual and forecasted; it may also coordinate with the department operations chief for field resources to monitor local environmental and asset conditions.

Enhanced Safety Settings (ESS) – Modes of operation for transmission and distribution operations during times of elevated wildfire risk. This includes adjustments to distribution relays during periods of elevated wildfire risk that are intended to minimize the energy release component through modified protective settings or operational practices and the removal of reclosing functionality on transmission with modified reclosing schemes on distribution assets based on daily wildfire risk thresholds and load restoration requirements. ESS modes will vary based on relay type and conditions.

Entire Circuit – Is the entire section of powerline(s) starting at a substation and extending away from the substation to the end of the line; it includes all fused or non-fused tap lines.

Fire High Consequence Areas (FHCA) – Are defined geographic areas of heightened wildfire risk with the potential for catastrophic wildfire impact.

Wildfire Potential – The Fire Risk Potential will be identified by meteorology as outlined in Section 9.

Full Outage Patrol – Requires confirmation that all overhead lines downstream of the open device as identified by fault data, including fused taps, have been visually patrolled and are clear and able to be safely energized. Based on fault location, the full patrol could be isolated to an area between devices.

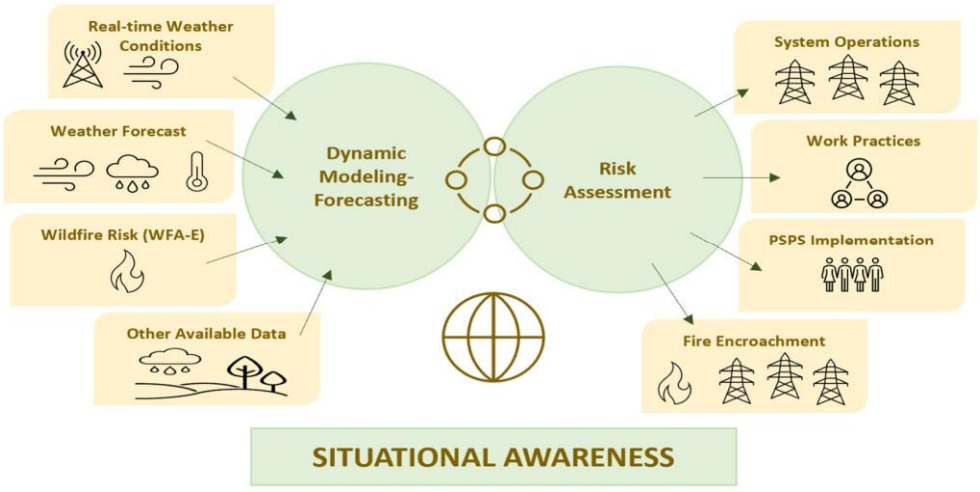
High Fire Threat District (HFTD) – Are geographic areas of heightened wildfire risk designated by California Office of Energy Infrastructure Safety and CALFIRE. HFTD is the California Public Utility Commission (CPUC) defined name in California like FHCA.

Public Safety Power Shutoff (PSPS) – Is a decision by an electric utility to proactively deenergize electrical infrastructure during periods of the greatest wildfire risk, generally based on extreme weather and critically dry fuels conditions.

4. PURPOSE

Managing wildfire risk transcends state boundaries and departments. During periods of identified wildfire risk, the various information and departments are coordinated by leveraging situational awareness assessments that inform the operational actions across the service territory. Figure 1 provides an overview of situational awareness inputs during periods of elevated wildfire risk.

Figure 1 – Situational Awareness



5. SUMMARY OF POLICY STRUCTURE

This policy is structured to include nine sections (Sections 6-9 and 14-18) describing the role of distinct departments within the Power Delivery organization, two sections (Section 10 and 11) provide a high-level overview of protection/reclosing adjustments that may be deployed when wildfire conditions have been identified, and two sections (Section 12 and 13) highlighting planned de-energization (Public Safety Power Shutoff) and response to a confirmed wildfire in the proximity of company assets. The gathering and evaluation of information by Power Delivery departments is used to inform decision making regarding operation and restoration of the transmission and distribution system during identified wildfire risk or a credible wildfire and aligns with and supports Public Safety Power Shutoff procedures as outlined in the PacifiCorp Public Safety Power Shutoff Playbook.

Department	Section	Section Summary Description
Emergency Management	Section 6	Describes Emergency Management's role to schedule, facilitate and coordinate regular operational meetings when wildfire conditions are elevated, significant, or extreme which could include the activation of an Emergency Coordination Center (ECC), in alignment with Public Safety Power Shutoff procedures.
Wildfire Intelligence Center (WIC)	Section 7	Department responsible for situational awareness and coordination of actions associated with threats to the electrical network from external hazards such as wildfires, storms, floods, etc.
Wildfire and Emergency Response	Section 8	Fire and Emergency Response Managers are district co-located personnel with training and background in fire complex incident management. Department personnel will deploy to wildfire incidents. to represent the company's interests and support operational response to wildfires.
Meteorology	Section 9	Describes Meteorology's role in issuing a daily briefing, published on business days unless otherwise requested, reflecting PacifiCorp's situational awareness of the wildfire conditions associated with various circuits and geographical areas, that Power Delivery will utilize to make daily operational decisions around work practices and network/system configurations.
System (Control Center) Operations	Section 14	Describes the Control Center's role in ESS setting management (distribution), transmission reclosing posture, encroachment policy, PSPS and the general oversight of electric network operation, resource deployment and monitoring and restoration processes when wildfire conditions are present.
Real-time Grid Engineering	Section 15	Describes Real-time Grid Engineering's role when wildfire conditions are present, and outage investigations associated with but not limited to ESS settings and failed equipment/material. Additionally, they will support Field Engineering with ESS device operational performance.
Field Engineering	Section 16	Describes Field Engineering's role in preparation for wildfire season and when wildfire conditions are present including reviewing ESS device information, supporting outage investigations, and providing outage and restoration support in coordination with Real-time Grid Engineering.

Technical Services	Section 17	Describes Technical Services role when wildfire conditions are present which includes supporting distribution and transmission system protection, and asset performance.
T&D Field Operations	Section 18	Describes the role of T&D Field Operations when operating in the various Wildfire Conditions, as identified by the Meteorology department under Section 9, including response, inspections, modification of the network and device adjustments as directed by the applicable control center.

Adjustments	Section	Section Summary Description
Distribution Protection Device Settings	Section 10	Provides a high-level overview of the intent and use of Enhanced Safety Setting (ESS) protection modes for various devices deployed on PacifiCorp's distribution circuits.
Transmission Reclosing	Section 11	Provides a high-level overview of transmission reclosing, protection settings functionality during identified wildfire conditions and the operational procedures to be utilized.

Response	Section	Section Summary Description
Public Safety Power Shutoff	Section 12	Provides a brief overview of criteria utilized to drive a timeline-based planned de-energization of distribution and transmission facilities.
Wildfire Encroachment	Section 13	Provides the policy for how the company operates the transmission and distribution systems when a wildfire is in the vicinity of and/or approaching an asset.

6. EMERGENCY MANAGEMENT

Emergency management may schedule and facilitate a daily meeting when elevated wildfire conditions are forecasted. Coordination meetings will be held and moderated by emergency management when meteorology has forecasted elevated wildfire risk (yellow), significant wildfire risk (orange), or extreme wildfire risk (red) conditions in the five-day weather and fire potential forecast. While other forecasted weather-related conditions may warrant a coordination meeting, any coordination meeting scheduled with respect to wildfire conditions may be cancelled at the discretion of management when new actions are limited or can easily be coordinated between System Operations and T&D Field Operations.

An Emergency Coordination Center (ECC) may be established based on the size and scope of wildfire risk. An ECC will be established if PacifiCorp is considering a Public Safety Power Shutoff (PSPS) or for an encroaching fire as outlined in SOP-203, but an ECC may also be established to support response activities across multiple internal and/or external organizations.

Emergency Management is responsible for coordination and communication with internal departments and external public safety partners, consistent with the Public Safety Power Shutoff and fire encroachment procedures.

6.1 COORDINATION MEETING

The coordination meeting may include participants from organizations identified in the table below.

Organization
T&D Field Operations
T&D Support Services
Region System Operations
Grid Operations
Emergency Management
Meteorology
Real-time Grid Engineering
Field Engineering
Vegetation Management
Corporate Communications
Customer Service
Regional Business Management
Wildfire Intelligence Center
Wildfire and Emergency Response

Frequency: As required

7. WILDFIRE INTELLIGENCE CENTER

The Wildfire Intelligence Center (WIC) is responsible for monitoring hazards that pose a threat to PacifiCorp's electrical and communication network, communities or personnel. Their primary responsibility is monitoring the status of wildland fires within the service territory, coordinating actions associated with threats to assets, and providing coordinated updates to stakeholders regarding status through resolution. The only exception to coordination and communication is when an Emergency Coordination Center (ECC) assumes authority of an event. Actions relative to that event only will be transferred to the ECC, The WIC will maintain responsibility for all non-ECC monitoring, coordination and communication.

8. WILDFIRE AND EMERGENCY RESPONSE

The Wildfire and Emergency Response team is a field-based team whose personnel come with a background in firefighting and complex fire incident management team coordination. Personnel will deploy and act as the liaison for the company in support of the company's interests relative to asset protection and risk as well as to coordinate and support field and vegetation actions related to asset protection, asset assessment, asset repair, and de-energization and re-energization of assets in a wildfire that is managed by a complex incident

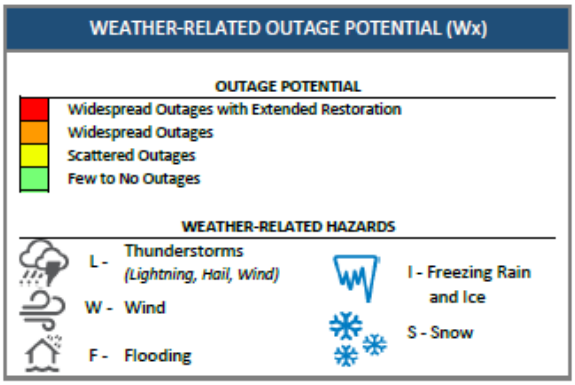
management team. These will generally be longer duration and larger complex events with impacts to transmission, distribution, communications, and/or generation assets. Short-duration encroachment events may be supported as requested by Wildfire Intelligence Center (WIC).

9. METEROLOGY

Meteorology will issue a briefing on the forecasted wildfire conditions for areas where PacifiCorp operates its transmission and distribution assets, which Power Delivery will use to make operational decisions.

9.1 ASSESSING WILDFIRE CONDITIONS

Meteorology will assign district-level wildfire conditions using weather, fuel and wildfire risk data sources. Wildfire risk will be expressed using a five-category scale as outlined below in the wildfire risk and weather-related outage potential tables.



When evaluating all areas of the service territory for wildfire risk, Meteorology performs a comprehensive review of fuels and fire weather conditions that include metrics and additional considerations outlined in the tables below.

TABLE 1 - Additional Weather, Fuel, and Wildfire Impact Assessment Sources

Additional Considerations When Assessing Wildfire Potential	
Wildfire Consequence Modeling (WFA-E)	Millions of wildfire simulations are performed daily to map out potential wildfire conditions, behavior, and consequence across the service territory.
Energy Release Component (ERC)	ERC is a composite fuel moisture value that measures the contributions all live and dead fuels have to potential fire intensity. The ERC is a cumulative or "build-up" type of index. As live fuels cure and dead fuels dry, the ERC values get higher thus providing a good reflection of conditions.
Burning Index (BI)	The Burning Index (BI) is derived from a combination of Spread and Energy Release Components expressed as a numeric value closely related to flame length in feet multiplied by ten. It is a number related to the contribution of fire behavior to the effort of containing fire.

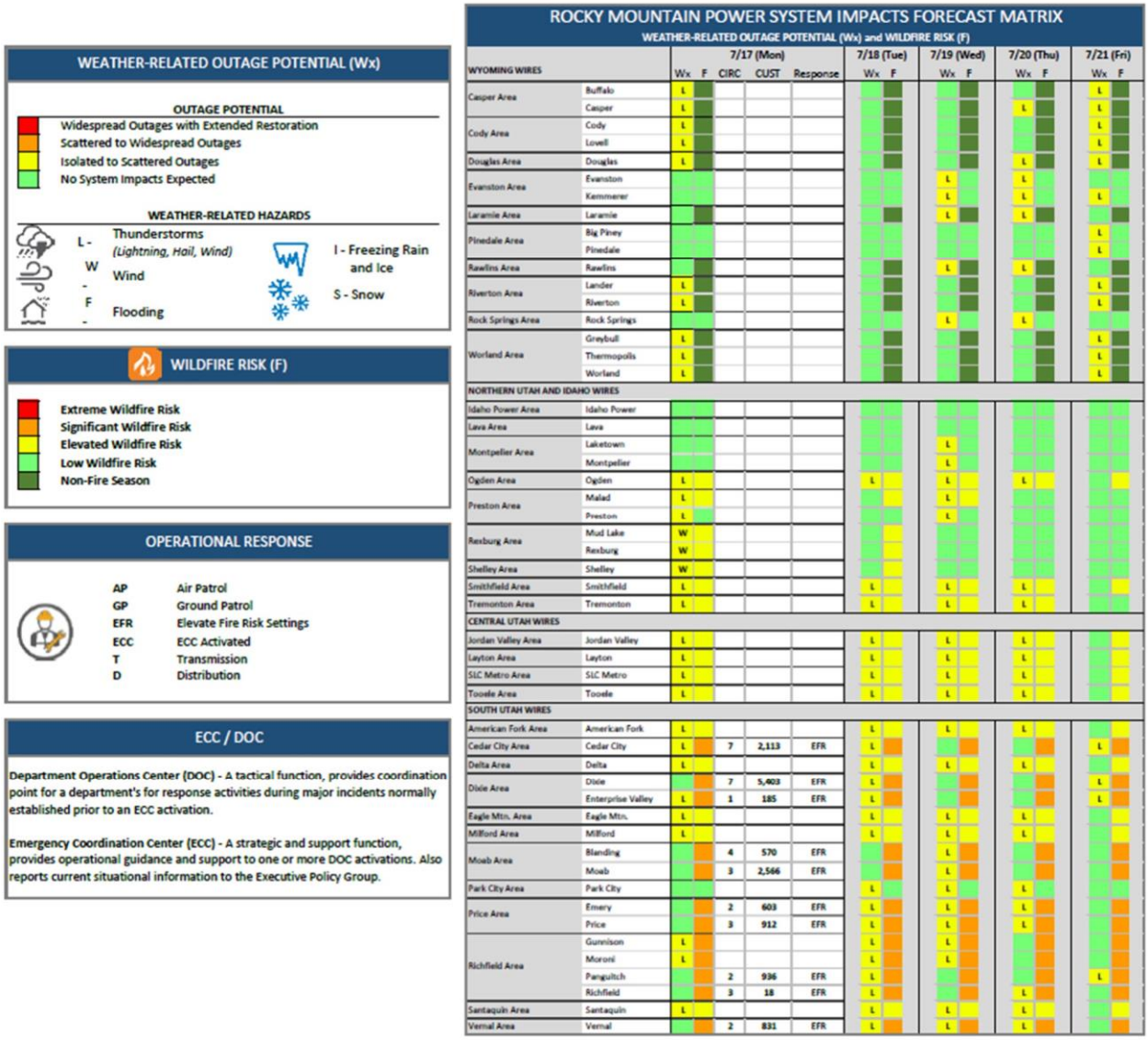
Geographic Area Coordination Centers (GACC)	Monitor the GACCs 7-Day Significant Wildfire Potential? Has a Fuels & Fire Behavior Advisory been issued?
National Weather Service Watches and Warnings	Has the National Weather Service issued a Fire Weather Watch, Red Flag Warning, or High Wind Warning for the area in question?
High Resolution Fire Weather Forecasts	PacifiCorp runs a 2km WRF model which produces a twice daily territory wide forecast of fire weather conditions across a 96-hour time horizon.
Evaporative Demand Drought Index (EDDI)	EDDI identifies anomalous atmospheric evaporative demand and provides an early warning of increased wildfire conditions.
Fuels Conditions (Live and Dead Fuels)	Observations of the local various fuel conditions. Are grasses fully cured and receptive to ignition? Are live fuels critically dry? Is there excessive tree mortality?
Current or Recent Wildfire Activity	Current or recent wildfire activity is an indication that the weather and fuels conditions will contribute to fire occurrence and spread.
Hot-Dry-Windy Index (HDWI)	HDWI considers wind speed and VPD to determine which days are more likely to have adverse conditions that make it more difficult to manage a wildland fire.
Vapor Pressure Deficit (1-month running average)	Vapor Pressure Deficit is a measure of the atmospheric demand (thirst) for water. Values above the 94th percentile have been associated with large wildfires.
Severe Fire Danger Index	Publicly available index that uses two United States National Fire Danger Rating System indices that are related to fire intensity and spread potential.
Fire Potential Index (FPI)	FPI quantifies the potential for large or consequential wildfires based on weather, fuels, and terrain.

Additional information not identified in Table 1 may be relevant to the situation and may, as appropriate, be included in the situational awareness assessment.

9.2 ASSESSING WEATHER RELATED SYSTEM IMPACTS

The PacifiCorp meteorology team analyzes weather model data and risk modeling output to produce a district-based, weather-related system impacts forecast as outlined in meteorology procedure MET-100. An example of this System Impacts Forecast Matrix is provided below for reference (Figure 2).

Figure 2 – Example of System Impacts Forecast Matrix



9.3 METEROLOGY ASSESSMENT CIRCUIT LEVEL OUPUT

As districts transition to wildfire risk forecasts of elevated wildfire risk or greater, System Operations and Field Operations will utilize the ESS Playbook, which is the system of record; to view circuit, or circuit segment, recommendations for operational action. Wildfire risks will be forecast by meteorology using geospatial polygons.

10. DISTRIBUTION – ENHANCED SAFETY SETTINGS (ESS)

ESS modes of operation on the distribution system are intended to reduce energy released during a fault event by enabling more sensitive fault current settings. PacifiCorp has many different relay devices in operation on the distribution system. Each relay device has a different

set of functions and limitations which may be deployed to reduce ignition risk when wildfire conditions are present. Prior to the onset of wildfire season, Meteorology develops fuels/terrain polygons which engineering utilizes to review ESS device Momentary Zone of Protection (ZOP). Once the device Momentary ZOP is associated to a polygon, meteorology generates a wildfire risk forecast to the polygon which is used to support ESS decision-making and updates to the ESS Playbook.

When wildfire conditions are forecasted per Table 2, the identified circuits or portion of a circuit and/or those circuits or portion of a circuit may have ESS settings applied as identified in the ESS Playbook unless an exception is approved through the ESS Playbook exception process. SOP-202 provides specific operational action based on ESS setting application and response.

As wildfire conditions can change based on weather and fuels, the decision to remove ESS settings when wildfire conditions transition to low wildfire risk (light green) as outlined in Table 2. Requests to remove ESS settings will be requested as an exception. Should wildfire conditions return to ELEVATED (yellow), ESS settings will be re-applied as directed in the ESS Playbook unless an exception is granted.

There will be a time where wildfire conditions are low (low risk, light green) based on weather and fuels. When an area transitions to low risk, light green, it signals that the forward-looking weather and fuel conditions have a low probability of ignition and support removal of ESS settings. In addition, there may be times when wildfire conditions remain in low wildfire risk (light green) for a period which would support removal of ESS settings, and those criteria are identified in Table 2.

Management does have the discretion to maintain ESS settings even if one or both criteria above are met. Removal of ESS settings will be guided by the ESS Playbook. Decision to maintain settings will be requested via the exception process.

TABLE 2 – ESS Implementation for Forecasted Conditions

	Risk	ESS Deactivation
	Non-Wildfire Operations	
	Low Risk	
EFR	Elevated Risk	1 Day Realized Light Green – 4 Days Forecasted Light Green
TAG	Significant Risk	
TAG	Extreme Risk	

11. TRANSMISSION – RECLOSING

Transmission is divided into two categories, bulk electric system (BES) and sub-transmission. Each transmission category provides a specific function within the delivery of electric service from source (generator) to the customer. Given most faults on the system are temporary (i.e. airborne debris, lightning, etc.), reclosing is utilized to restore a line after a temporary fault. If the fault is still present during the reclose cycle, the line will remain open (lock out). When

wildfire conditions escalate, the disabling of automatic reclosing or discontinuing the use of manual reclosing after an operation or a set number of operations is an option for real-time operators and/or management to minimize the potential of an ignition. Otherwise, transmission reclosing will be disabled based on Table 3. An exception can be submitted to grid operations to maintain reclosing during Significant (orange) and/or Extreme (red) and must be approved by a Power Delivery Director or above.

Reference SOP-200 for operating the BES and SOP-201 for operating sub-transmission during identified wildfire risk.

TABLE 3 –Transmission Reclosing for Forecasted Conditions

	Risk	Notes
	Non-Wildfire Operations	
	Low Risk	
	Elevated Risk	
Reclose OFF	Significant Risk	
Reclose OFF	Extreme Risk	

12. PUBLIC SAFETY POWER SHUTOFF

When weather and fuels dictate, PacifiCorp has outlined requirements to initiate the process for planned de-energization (Public Safety Power Shutoff) of distribution and transmission facilities based on specific timeline-based criteria outlined in meteorology procedure MET-100 and the Public Safety Power Shutoff Playbook. The procedure outlines the standard timeline criteria utilized for a public safety power shutoff as forecasted conditions continue to develop. In addition, MET-100 has identified criteria that triggers a transmission level public safety power shutoff discussion. It is understood that weather may not support the standard timeline, and a step(s) could be accelerated or omitted.

13. WILDFIRE ENCROACHMENT (EMERGENCY DE-ENERGIZATION)

PacifiCorp has outlined requirements for emergency de-energization of transmission lines, distribution lines, and/or substation facilities based on approaching wildfires in procedure SOP-203. The procedure outlines the actions to be taken by various departments within the organization when a credible wildfire is within specified proximity of an identified company asset.

14. SYSTEM (CONTROL CENTER) OPERATIONS

In all circumstances, System Operations is the central hub for communications associated with the transmission and distribution networks. During periods of identified wildfire conditions, System Operations (Grid and Region) will manage the system, outage response, and direct restoration efforts consistent with the procedures identified in Section 2 (REFERENCES).

Restoration authority changes with increased wildfire risk to reduce the potential for ignition where operator restoration authority decreases and management involvement is introduced. Operational restoration authority is outlined in operational procedures referenced in Section 2.

With respect to Section 10, Region System Operations will act as the central control coordinating with T&D Field Operations to issue and track activation or deactivation of distribution ESS settings by device. The ESS Playbook is the system of record for activation, deactivation and exception records tied back to EMS records input by System Operations.

With respect to Section 11, Grid Operations will act as the central control coordinating with Region System Operations and T&D Field Operations to issue, track and authorize disabling or re-enabling of transmission reclosing by device. This includes managing the exception process. Prior to fire season, System Operations will pro-actively identify sub-transmission lines that may be removed from service as identified wildfire conditions intensify. Pre-identified lines may be removed from service when the identified wildfire risk is significant (orange) or extreme (red) unless otherwise directed by management. Any transmission that was pro-actively removed from service must be fully visually patrolled prior to re-energization.

As the Bulk Electric System (BES) transmission lines support a larger regional aspect of connecting generation to load across the western interconnect, procedure SOP-010 establishes the study criteria to identify system impacts associated with the removal of a BES transmission line when wildfire risk is significant (orange) or extreme (red). Pro-active removal of a BES transmission line does require coordination with the reliability coordinator (RC) before or after de-energization depending on the situation.

15. REAL-TIME GRID ENGINEERING

Real-time Grid Engineering facilitates coordination and collaboration between Field Engineering, Protection and control Engineering and Technical Services personnel on wildfire circuit protection development and implementation. This includes investigating relay equipped device level distribution outages which may include but not limited to fire incidents associated with a device operation or material failure (i.e. wire down, etc.) incidents. Depending on the situation, real-time engineering will obtain relay data (which may include waveform capture) to assist with the investigation. As a result of the investigation, corrective actions may be identified and communicated to the appropriate organization(s) for resolution.

In addition to the investigations, Real-time Grid Engineering will provide restoration support to the control center operators when required and provide support for ESS setting device activations. The restoration support could include providing technical support to retrieve relay fault data and event waveforms, supplying fault location information, adjusting protective device settings, and/or troubleshooting a protective device operation. The ESS device setting activation support could include reviewing ESS devices being activated based on meteorology fuels/terrain polygons/wildfire risk forecast, confirming settings/capability of the ESS device, and selection of relay control tables so that activation orders can be provided.

16. FIELD ENGINEERING

Field Engineering has the responsibility to review ESS device information in preparation for wildfire season and as wildfire conditions become present. This includes a review of the ESS device location information, settings/capability of the ESS device, and ESS device momentary zone of protection with respect to Meteorology fuels/terrain polygons.

In addition to ESS device setting activations, Field Engineering will provide outage restoration and outage investigation support to Real-Time Grid Engineering when required due to volume.

17. TECHNICAL SERVICES

Technical Services supports the development, testing, and implementation of distribution relay settings utilized to mitigate ignition risk in coordination and collaboration with Protection and Control Engineering and Real-time Grid Engineering.

While the Real-time Grid Engineers are responsible for distribution level investigations, the Technical Services team investigates bulk electric system transmission and sub-transmission level operations which can include momentary operations. Like Real-time Grid Engineering, Technical Services will obtain relay data (which may include waveform capture) to assist with the investigation. As a result of the investigation, corrective actions may be identified and communicated to the appropriate organization(s) for resolution.

When requested, Technical Services can also aid Real-time Grid Engineers with restoration and troubleshooting activities, as well as, provide investigation support for distribution outage events.

18. T&D FIELD OPERATIONS

T&D Field Operations personnel will (under the direction of System Operations) implement device setting or reclosing functionality modifications as outlined in Sections 10 and 11 for identified devices when forecasted wildfire conditions are present as forecasted by meteorology. The same process will be followed when placing a device setting or reclosing functionality back to normal operation.

T&D Field Operations personnel are not permitted to restore after sunset or before sunrise when significant wildfire conditions (orange) have been identified by meteorology unless approved by a Power Delivery Director (or Director designee) or above.

T&D Operations personnel will not restore when extreme wildfire conditions (red) have been identified by meteorology unless approved by a Power Delivery Vice President (or above) or the ECC Executive.

The wildfire risk identified by the Meteorology Department may impact field operations. In general, whenever wildfire conditions are not present (non-wildfire operations, dark green) or are low wildfire risk (light green), work may be conducted using normal operating practices.

When the Meteorology Department however, forecasts elevated wildfire conditions, local T&D Field Operations may modify operating practices as outlined in the table below. For example, certain personal protective equipment and basic fire-fighting tools are necessary for any field work when wildfire conditions have been identified. Local area management will also evaluate, after considering multiple factors regarding the local circumstances of a particular circuit (i.e. asset health, inspections, vegetation, etc.), whether any hot work modifications should be made. If wildfire conditions are significant or extreme, local area management will also consider whether any additional work might be appropriate.

1. When a circuit is identified as having elevated wildfire risk or above – meaning YELLOW, ORANGE or RED – local area management will complete an Elevated Fire Risk Work Evaluation (using a standard checklist form for that purpose).

2. When a circuit is identified as having significant wildfire risk or above – meaning ORANGE or RED – in addition to the actions in No. 1 above, local area management will complete an Additional Work Evaluation (using a standard checklist form for that purpose).

3. When a circuit is identified as having extreme wildfire risk– meaning RED – in addition to the actions in No. 1 and No. 2 above, local area management will cancel planned hot work (instead of considering alternatives as part of a Hot Work Evaluation).

The activities of T&D Field Operations, with respect to a particular category of identified wildfire risk, are summarized in the following table:

18.1 WORK EVALUATION FOR ELEVATED WILDFIRE CONDITION DAYS

Wildfire Conditions Yellow	Wildfire Conditions Orange	Wildfire Conditions Red
PPE Equipment and Tools Daily Hot Work Evaluation	PPE Equipment and Tools Daily Hot Work Evaluation Additional Work Evaluation	PPE Equipment and Tools Cancel Hot Work Additional Work Evaluation

19. TRAINING PLAN

The following departments have been identified to receive training on this policy.

Organization	Personnel	Method
Grid Operations	Operators	Instructor Lead
Grid Operations	Management	Document Review
Region System Operations	Outage Coordinators	Instructor Lead
Region System Operations	Operators	Instructor Lead
Region System Operations	General Foreman	Instructor Lead
Region System Operations	Management	Document Review

Policy

System Operations	Management	Document Review
T&D Field Operations	Field Personnel	Instructor Lead
T&D Field Operations	Management	Document Review
Emergency Management	All	Document Review
Meteorology	All	Document Review
Technical Services	All	Document Review
Real-time Grid Engineering	All	Document Review
Field Engineering	All	Document Review
Wildfire Intelligence Center	All	Document Review
Wildfire & Emergency Response	All	Document Review

1Operating BES Transmission Assets During Identified Wildfire Risk
System Operations Procedure SOP-200

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Operating BES Transmission Assets During Identified Wildfire Risk
System Operations Procedure SOP-200

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1. SCOPE

PacifiCorp has comprehensive plans for wildfire mitigation efforts designed to reduce the probability of utility related wildfire ignition and to mitigate damage to company assets. This policy addresses the company's approach to adjusting daily operations of Bulk Electric System transmission assets, including network restoration, during identified periods of elevated wildfire risk. This procedure does not override de-energization requirements outlined in SOP-203 (Wildfire Encroachment).

2. REFERENCES

PAC-1000	Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk
SOP-200	Operating Bulk Electric System Assets During Identified Wildfire Risk
SOP-201	Operating Sub-transmission Assets During Identified Wildfire Risk
SOP-202	Operating Distribution Assets During Identified Wildfire Risk
SOP-203	Wildfire Encroachment

3. COMMON ACRONYMS

BES	Bulk Electric System
ECC	Emergency Coordination Center
EMS	Energy Management System

4. PURPOSE

The purpose of this Operating Procedure SOP-200-BEST is to provide guidelines for operating bulk electric system (BES) transmission assets and other transmission facilities regulated by NERC during periods of identified wildfire risk. This Procedure has been developed to balance risks associated with system reliability-stability and wildfire. It implements specific procedures for System Operations during times of identified wildfire risk as identified by meteorology for each of PacifiCorp's operating districts.

5. BULK ELECTRIC SYSTEM

PacifiCorp's BES transmission supports the movement of generation to load in a large portion of the Western Interconnection as identified below. The BES transmission interconnects multiple utilities and provides the ability to move generation to load where

the generation and load are regionally separated. Loss of a BES transmission element does not only have a local impact but can also have impacts regionally and/or to the western interconnected system. BES transmission is operated to maintain system stability and reliability regionally and within the Western Interconnection.

Figure 1. The Four Interconnected Electric Systems in the United States and Canada

6. JOINT OWNED & INTERCONNECTED FACILITIES

Based on the interconnected nature of the bulk electric system (BES) within the Western Interconnection, there are times when facilities are joint-owned and/or operated by PacifiCorp or another utility; there are also circumstances where PacifiCorp facilities are interconnected to facilities owned and operated by another utility (i.e. PacifiCorp owns 20 miles of a transmission line and another utility owns 30 miles of the same transmission line). Any operational adjustments associated with joint owned, operated, and/or interconnected facilities must be coordinated and communicated with all owners/operators. With respect to this procedure, the items identified below will be coordinated with owners and operators when wildfire risk potential is yellow, orange, or red.

- Disabling reclosing/no manual reclose
- Decision not to test or manually close after a transmission line has opened.
- Patrol requirements.

In the event an owner and/or operator does not agree with PacifiCorp's operational adjustment(s), the grid operations director or identified delegate shall be notified immediately so the situation can be escalated with the appropriate owner and/or operator.

7. WILDFIRE RISK POTENTIAL – OPERATIONAL AUTHORITY

As set forth in PAC-1000, the meteorology organization will communicate the wildfire risk level for each district. The wildfire risk level is expressed using a color-coded system, with four levels: green, yellow, orange, and red. Dark green indicates normal operations. Control center operators shall modify system operations, based on the color and daily situation awareness reviews as identified in the weather briefing. The wildfire risk level may modify operational authority for inspecting, testing or re-energizing a line, which may include associated equipment, as summarized in the following table:

Wildfire Risk Potential	Operational Authority	Comments
Non-Wildfire Operations*	Operator	Operator follows normal operating procedures and has normal restoration authority to close.
Low	Operator	Prior to a patrol, Operator has operational authority to restore based on no identified hazards and favorable weather conditions.
Elevated	Operator or Power Delivery Manager	Operator has limited authority to restore without patrol based on meeting weather condition criteria or receipt of patrol maps and/or opening pre-identified isolation points. Director can authorize to restore without patrol if weather criteria is not met or without engineering patrol maps and/or opening pre-identified isolation points.
Significant	Grid Ops Director or above	**Operator does not have operational authority to test or re-energize without patrol,** without approval from a Power Delivery director (or above) or identified delegate.
Extreme	ECC, PD Vice President, or above	**Operator does not have operational authority to test or re-energize without approval** from the Emergency Coordination Center (ECC), a Power Delivery Vice President (or above), or identified delegate.

*Dark green will be identified with a with a white NORMAL on a black background where the color normally resides on the energy management system screen.

8. RE-ENERGIATION AFTER SOP-203 DE-ENERGIZATION

Light Green (Low Wildfire Risk)

After a wildfire encroachment emergency de-energization, restoration of some or all the assets may be performed by the operator after completing the re-energization checklist as outlined in SOP-203. Assets de-energized outside the wildfire encroachment radius due to limited SCADA control, or other equipment limitations, may be restored by the operator as soon as possible.

Yellow/Orange (Elevated/Significant Wildfire Risk)

After a wildfire encroachment emergency de-energization, restoration of some or all the assets, within the fire encroachment radius as described in SOP-203, requires a Power Delivery Director approval. Assets de-energized outside the wildfire encroachment radius due to limited SCADA control may be restored by the operator without director approval following the re-energization requirements below.

9. ITEMS FOR CONSIDERATION DURING IDENTIFIED WILDFIRE RISK

i. **Reliability-Stability Factors**. Western interconnect stability and reliability shall be evaluated to ensure the interconnection remains stable and can support load service. A large Western Interconnect event may require an immediate restoration attempt, despite extreme wildfire conditions. When these procedures require approval prior to testing or re-energizing a line, it is imperative for the operator to promptly make all reasonable efforts to notify management of the situation before taking any action to test or re-energize. The following may be evaluated to determine appropriate actions to maintain system stability and load service capability.

In assessing reliability-stability, the following are some of the factors to consider:

a.	Are any RTCA violations observed?
b.	Is a ***Level 1*** Generation Alert in effect?
c.	Are there any Energy Emergency Alerts (EEAs) in effect?
d.	Does this put PacifiCorp into an Energy Emergency Alert situation?
e.	Does this put another entity into an Energy Emergency Alert situation?
f.	Are there any Reliability Coordinator alerts?
g.	Has the Reliability Coordinator issued a directive?
h.	Does this impact any generation facilities?
i.	Does this impact adjoining (interconnected) entities?
j.	Does this impact PacifiCorp's load service?
k.	Does this impact another entity's ability to serve load?
l.	Does this require PacifiCorp to proactively load shed?
m.	Does this impact any PacifiCorp large customer accounts?

This list is not exhaustive, and other reliability information may be pertinent to maintain system stability and load service.

ii. **Wildfire Risk Factors**. The wildfire risk level communicated by meteorology establishes a baseline risk level for a district. Operators may, however, obtain additional information to further understand the risk level for a particular asset. For example, a long transmission line traversing different topographical areas likely has varying degrees of wildfire risk over varying segments of the line and will be operated at highest risk level identified across the length of the line. When a

transmission line is under any elevated level of wildfire risk, operators should generally gather additional information about the local weather, asset health, and environmental conditions, as needed to help inform operational decisions. An operator can consider the following factors:

a.	Across the line or line section impacted does www.pacificorpweather.com show • Humidity higher than 50% • Wind gusts less than 10mph
b.	Is it raining across part of or the entire transmission line?
c.	Is there lightning in the area based on www.LightningMaps.org or other sites?
d.	Check other real-time weather tools if applicable?
e.	If available, is the line or portion of the line identified based on fault location information as a concern by meteorology?
f.	What type of terrain does the transmission line traverse?
g.	When feasible and based on the length of a transmission line, verify with field personnel to confirm locally observed weather conditions?
h.	Have any hazard conditions been communicated or identified by other means (i.e. field personnel, 911, interconnecting entity, etc.)?

10. PROCEDURE – BES TRANSMISSION

Normal outage notification procedures will be utilized in all cases when an operation occurs.

A. Fire Risk Potential - Black with white NORMAL on EMS screen

i. Normal operating procedures apply, and an operator has operational authority to test without a patrol, sectionalize/isolate and restore, or re-energize after a patrol.

B. Fire Risk Potential – Light Green Scenario (1): *line trips and auto recloses*

i. Upon the trip and reclose of the transmission line, a 12-hour Expiring Fire Mitigation Tag will be applied in EMS.

ii. If the transmission line trips and recloses two times within a 12-hour period, follow the steps below:

1. Turn off reclosing.
2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.

3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.
4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
    - Grid Operations Manager
    - Grid Operations Director
    - System Operations Vice President
    - Or identified delegate.

C. Fire Risk Potential – Light Green Scenario (2): *line trips to lockout with manual reclose by design*

i. Operator will follow standard operating procedure and test one time.

1. **If close is successful.**
    a. Apply a 12-hour Expiring Fire Mitigation Tag in EMS.
    b. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.
    c. Request a patrol of the line during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
2. **If close is not successful.**
    a. Continue to D.

ii. If the transmission line trips with successful manual reclose two times within a 12-hour period, follow the steps below:

1. No further manual reclose attempts until the line is patrolled or as directed by management.
2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.

3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning

4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:

    - Grid Operations Manager
    - Grid Operations Director
    - System Operations Vice President
    - Or identified delegate.

D. Fire Risk Potential – Light Green Scenario (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 9.

1. If the assessment indicates no impact, leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or faulted section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Grid Operations Manager, Grid Operations Director, System Operations Vice President, or identified delegate. Refer to Section 9 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from the Grid Operations Manager, Grid Operations Director, System Operations Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morningtoo close to end of daylight, data will be pulled when first responder is onsite the next morning

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 9. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with the:
   - Grid Operations Manager
   - Grid Operations Director
   - System Operations Vice President
   - Or identified delegate.

E. Fire Risk Potential – Yellow Scenario (1): *line trips and auto recloses*

i. Upon the trip an reclose of the transmission line, a 12-hour Expiring Fire Mitigation Tag will be applied in EMS.

ii. If the transmission line trips and recloses two times within a 12-hour period, follow the steps below:

1. Turn off reclosing.
2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.
3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morningtoo close to end of daylight, data will be pulled when first responder is onsite the next morning
4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
   - Grid Operations Manager
   - Grid Operations Director
   - System Operations Vice President
   - Or identified delegate.

F. Fire Risk Potential – Yellow Scenario (2): *line trips to lockout with manual reclose by design*

i. If the use of reclosing is not allowed at the direction of management go to G, otherwise follow the steps below. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Apply a 12-hour Expiring Fire Mitigation Tag in EMS.

b. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

c. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Continue to G.

ii. If the transmission line trips with successful manual reclose two times within a 12-hour period, follow the steps below:

1. No further manual reclose attempts until the line is patrolled or as directed by management.

2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.

3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

4. Request a patrol of the line or isolated line section during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
   - Grid Operations Manager
   - Grid Operations Director
   - System Operations Vice President
   - Or identified delegate.

G. Fire Risk Potential - Yellow Scenario (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 9.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

1. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

2. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

3. Request an immediate line patrol to be conducted and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Grid Operations Manager, Grid Operations Director, System Operations Vice President, or identified delegate. Refer to Section 7 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from the Grid Operations Manager, Grid Operations Director, System Operations Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. **If close is successful.**

   a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

   b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. **If close is not successful.**

   a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

   b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

   c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

   d. Any further action must be coordinated with the:
      - Grid Operations Manager
      - Grid Operations Director
      - System Operations Vice President
      - Or identified delegate.

H. Fire Risk Potential – Orange Scenario (1): *line trips and auto recloses*

i. Turn off reclosing.

ii. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

iii. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

iv. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
- Grid Operations Director
- System Operations Vice President
- Or identified delegate.

I. Fire Risk Potential – Orange Scenario (2): *line trips to lockout with manual reclose by design*

i. If the use of reclosing is not allowed at the direction of management go to J, otherwise follow the steps below.

ii. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur after 5pm, dispatch the following morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available.

2. If close is not successful.

a. Go to J.

J. Fire Risk Potential - Orange Scenario (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 7.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data.

b. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate line patrol to be conducted and provide the line patrol personnel with the fault information once available.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Grid Operations Director, System Operations Vice President, or identified delegate. Refer to Section 7 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from the Grid Operations Director, System Operations Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section,

and restore customers and/or generation per Section 7. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with and approved by the:
   - Grid Operations Director
   - System Operations Vice President
   - Or identified delegate.

K. Fire Risk Potential - Red Scenario (1): *line trips and recloses*

i. Turn off reclosing.

ii. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

iii. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management. iv. Return reclosing to the pre-event state after patrol and approval from the:

- Emergency Coordination Center
- Power Delivery Vice President
- Or identified delegate.

L. Fire Risk Potential – Red Scenario (2): *line trips to with manual reclose by design*

i. If the use of reclosing is not allowed at the direction of management go to M, otherwise follow the steps below.

ii. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur after 5pm, dispatch the following morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available.

2. If close is not successful.

a. Go to M.

M. Fire Risk Potential - Red Scenario (3): *line trips to lockout*

i. Leave line out of service.

ii. Operator shall assess the situation and may also consider items outlined in Section 7.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. Request an immediate line patrol and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. If fault location is known via and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol of the line or isolated line section to be conducted and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to iii.

iii. Gather information for restoration discussion with the Emergency Coordination Center (ECC), Power Delivery Vice President, or identified delegate. Refer to Section 7 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iv. Upon receiving approval to test from the Emergency Coordination Center (ECC), Power Delivery Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder immediately to retrieve the data unless otherwise directed by management.

b. If not completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with the:

- Emergency Coordination Center
- Power Delivery Vice President
- Or identified delegate.

11. PROCEDURE – TRANSMISSION LINE SECTIONALIZING

Generally, BES transmission is a higher voltage supporting the transfer of power over a long distance from generation sources to support load service. In some cases, a BES transmission line also provides local load service like a sub-transmission line. When a permanent fault occurs on a BES transmission line providing load service, the power transfer capability is lost but the line can usually be sectionalized automatically or manually to maintain load service. In addition, BES transmission lines are generally

equipped with protective relays that can provide fault location information which can be used by the operator if the system is not designed to automatically sectionize.

While not as common on the bulk electric system (BES), operating transmission line switches outside a substation have additional considerations. Transmission line switches outside a substation and within an area of identified fire risk will be operated with a load break device such as a multiple bottle interrupter (i.e. TECO-Rupter or Monorupter) or a SF6 interrupter (i.e. LLS-II). A switch with whips and a single bottle is not sufficient to prevent arcing during switching. Switches without an appropriate load break device will require the vegetation around the switch location to be cleared, the area to be watered down and a water truck on standby prior to the switch being operated.

Deadline switching is also an option if switches do not have a load break device or if weather conditions exist where clearing vegetation and watering will not be effective. If deadline switching activities will create a customer outage longer than five minutes, then customer notification (outbound call) is required prior to performing switching activities.

In the scenario where a BES transmission line automatically sectionalizes isolating the faulted section of transmission line, there is **NO** need to turn reclosing off on the remaining source(s). Follow the applicable identified fire risk lockout procedure for restoration of the faulted line section.

In the scenario where a BES transmission line must be sectionalized manually or the auto-sectionalizing scheme failed to operate, the fault location provided by the protective relays shall be used to identify the section of line to be isolated. Field response shall be notified to complete isolation switching of the faulted section prior to patrolling. In the case where an auto-sectionalizing scheme failed to operate, the operator can remotely isolate the faulted section of line. In both these cases, there is **NO** need to turn reclosing off on the remaining source(s).

12. NERC EVIDENCE

This document is used as evidence for the following NERC standard requirements:

- EOP-011-1, Requirement 1.2.6.

13. TRAINING PLAN

This document will be updated annually prior to System Operations operator spring training. The following departments have been identified to receive training on this policy. For the Instructure Lead training, Document Review is also required.

Organization	Personnel	Method
Grid Operations	Operators	Instructor Lead
Grid Operations	Management	Document Review
Region System Operations	Outage Coordinators	Instructor Lead
Region System Operations	Operators	Instructor Lead
Region System Operations	General Foreman	Instructor Lead
Region System Operations	Management	Document Review
System Operations	Management	Document Review
T&D Field Operations	Field Personnel	Instructor Lead
T&D Field Operations	Management	Document Review
Emergency Management	All	Document Review
Meteorology	All	Document Review
Technical Services	All	Document Review
Real-time Grid Engineering	All	Document Review
Renewables Operations	Operators	Instructor Lead
Renewables Operations	Management	Document Review

APPENDIX 1 – BULK ELECTRIC SYSTEM TRANSMISSION FLOW CHART

Refer to associated SOP-200 Flowchart document.

Operating Sub-Transmission Assets During Identified Wildfire Risk
System Operations Procedure SOP-201

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Operating Sub-Transmission Assets During Identified Wildfire Risk
System Operations Procedure SOP-201

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1. SCOPE

PacifiCorp has comprehensive plans for wildfire mitigation efforts designed to reduce the probability of utility related wildfire ignition and to mitigate damage to company assets. This policy addresses the company's approach to adjusting daily operations of Sub-transmission assets, including network restoration, during identified periods of elevated wildfire risk. This procedure does not override de-energization requirements outlined in SOP-203 (Wildfire Encroachment).

2. REFERENCES

PAC-1000	Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk
SOP-200	Operating Bulk Electric System Assets During Identified Wildfire Risk
SOP-201	Operating Sub-transmission Assets During Identified Wildfire Risk
SOP-202	Operating Distribution Assets During Identified Wildfire Risk
SOP-203	Wildfire Encroachment

3. COMMON ACRONYMS

BES	Bulk Electric System
ECC	Emergency Coordination Center
EMS	Energy Management System

4. PURPOSE

The purpose of this Operating Procedure SOP-201 is to provide guidelines for operating sub-transmission assets during times of identified wildfire risk. This Procedure has been developed to balance risks associated with local load service and wildfire. It implements specific procedures for System Operations during times of identified wildfire risk as identified by meteorology for each of PacifiCorp's operating districts.

5. SUB-TRANSMISSION SYSTEM

The sub-transmission system is utilized to support local load service. It is generally a lower voltage than the bulk electric system (BES) transmission that supplies distribution substations in a localized area. Sub-transmission lines are generally not looped (connected through to two sources) but are connected to a single source. It is rare for a sub-transmission line to be looped but, in most cases, there is a normally open point between

two sources that allows load to be transferred automatically or manually to the other source.

6. JOINT OWNED & INTERCONNECTED FACILITIES

Based on the interconnected nature of the electric system there are times when facilities are joint-owned and/or operated by PacifiCorp or another utility; there are also circumstances where PacifiCorp facilities are interconnected to facilities owned and operated by another utility (i.e. Sourced from another utility's substation.). Any operational adjustments associated with joint owned, operated, and/or interconnected facilities must be coordinated and communicated with all owners/operators via Grid Operations. With respect to this procedure, the items identified below will be coordinated with owners and operators when wildfire risk potential is yellow, orange, or red.

- Disabling reclosing/no manual reclose
- Decision not to test or manually close after a transmission line has opened.
- Patrol requirements.

In the event an owner and/or operator does not agree with PacifiCorp's operational adjustment(s), the grid operations director or identified delegate shall be notified immediately so the situation can be escalated with the appropriate owner and/or operator.

7. WILDFIRE RISK POTENTIAL – OPERATIONAL AUTHORITY

As set forth in PAC-1000, operational executive management will declare fire season for an operational district or districts and the meteorology organization will communicate the wildfire risk level for each district. The wildfire risk level is expressed using a colorcoded system, with four levels: dark green, light green, yellow, orange, and red. Dark Green indicates normal operations. Control center operators shall modify system operations, based on the color identified in the weather briefing. Above all, the wildfire risk level may modify operational authority for testing or re-energizing a line, as summarized in the following table:

Wildfire Risk Potential	Operational Authority	Comments
Non-WildfireOperations*	Operator	Operator follows normal operating procedures and has normal restoration authority to close.
Low	Operator	Prior to a patrol, Operator has operational authority to restore based on no identified hazards and favorable weather conditions.
Elevated	Operator or Power Delivery Manager	Operator has limited authority to restore without patrol based on meeting weather condition criteria or receipt of patrol maps and/or opening pre-identified isolation points. Director can authorize to restore without patrol if weather criteria is not met or without engineering patrol maps and/or opening pre-identified isolation points.
Significant	Power Delivery Director or above	**Operator does not have operational authority to test or re-energize without patrol,** without approval from a Power Delivery director (or above) or identified delegate.
Extreme	ECC, PD Vice President, or above	**Operator does not have operational authority to test or re-energize without approval** from the Emergency Coordination Center (ECC), a Power Delivery Vice President (or above), or identified delegate.

*Dark green will be identified with a with a white NORMAL on a black background where the color normally resides on the energy management system screen.

8. RE-ENERGIZATION AFTER SOP-203 DE ENERGIZATION

Light Green (Low Wildfire Risk)

After a wildfire encroachment emergency de-energization, restoration of some or all the assets may be performed by the operator after completing the re-energization checklist as outlined in SOP-203. Assets de-energized outside the wildfire encroachment radius due to limited SCADA control, or other equipment limitations, may be restored by the operator as soon as possible.

Yellow/Orange (Elevated/Significant Wildfire Risk)

After a wildfire encroachment emergency de-energization, restoration of some or all the assets, within the fire encroachment radius as described in SOP-203, requires a Power Delivery Director approval. Assets de-energized outside the wildfire encroachment radius due to limited SCADA control may be restored by the operator without director approval following the re-energization requirements below.

9. ITEMS FOR CONSIDERATION DURING IDENTIFIED WILDFIRE RISK

The sub-transmission system supports localized load service. An event on the sub-transmission line can impact part of a large community and/or several small communities. The following can be considered when evaluating the appropriate actions to maintain localized load service.

a.	Fault location available?
b.	Did the device complete the reclose cycle or go straight to lockout?
c.	Is the transmission line in an abnormal state?
d.	What type of terrain does the line run through and if fault location is available, what type of terrain is in the area?
e.	Is the line or portion of the line identified as FHCA by meteorology?
f.	Is it raining across part of or the entire circuit? (www.pacificorpweather.com)
g.	Is there lightning in the area based on www.LightningMaps.org?
h.	Across the line or line section impacted does www.pacificorpweather.com show • Humidity higher than 50% • Wind gusts less than 10mph
i.	Is there an active fire in the area?
j.	Does the weather conditions in the field (discussion with the first responder) match that identified on the weather website(s)?
k.	Does the first responder have any concerns energizing based on local weather and/or asset performance conditions?
l.	Have any hazard conditions been communicated or identified by other means (i.e field personnel, 911, interconnecting entity, etc.)?

This list is not exhaustive, and other information may be pertinent to support local load service.

10. PROCEDURE – SUB-TRANSMISSION

Normal outage notification procedures will be utilized in all cases when an operation occurs.

A. Fire Risk Potential – Black with White NORMAL (on EMS Screen)

i. Normal operating procedures apply, and an operator has operational authority to test without a patrol, sectionalize/isolate and restore, or re-energize after a patrol.

B. Fire Risk Potential – Light Green Scenario (1): *line trips and auto recloses*

i. Upon the trip and reclose of the transmission line, a 12-hour Expiring Fire Mitigation Tag will be applied in EMS.

ii. If the transmission line trips and recloses two times within a 12-hour period, follow the steps below:

1. Turn off reclosing.
2. Change the previously applied expiring fire mitigation tag to non-expiring fire mitigation tag with a note as to why reclosing is off, and when patrol was requested.
3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a first responder to retrieve the data. If the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.
4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
   - Power Delivery Manager
   - Power Delivery Director
   - Power Delivery Vice President
   - Or identified delegate.

C. Fire Risk Potential – Light Green Scenario (2): *line trips to lockout with manual reclose by design/delegation*

i. Operator will follow normal operating procedure and test one time.

1. **If close is successful.**
   a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.
   b. Request a patrol of the line during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
2. **If close is not successful.**

a. Continue to D.

ii. If the transmission line trips and recloses two times within a 12-hour period, identified through the use of Expiring Fire Mitigation Tags, follow the steps below:

1. Turn off reclosing.
2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.
3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur after 5pm, dispatch the following morning unless otherwise directed by management.
4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.
5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
   - Power Delivery Manager
   - Power Delivery Director
   - Power Delivery Vice President
   - Or identified delegate.

D. Fire Risk Potential – Light Green (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 9.

1. If the assessment indicates no impact, leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or faulted section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Power Delivery Manager, Power Delivery Director, Power Delivery Vice President, or identified delegate. Refer to Section 9 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from a Power Delivery Manager, Power Delivery Director, Power Delivery Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Apply a 12-hour Expiring Fire Mitigation Tag in EMS.

b. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

c. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or faulted section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with a:
   - Power Delivery Manager
   - Power Delivery Director
   - Power Delivery Vice President
   - Or identified delegate.

E. Fire Risk Potential – Yellow Scenario (1): *line trips and auto recloses*

i. Upon the trip and reclose of the transmission line, a 12-hour Expiring Fire Mitigation Tag will be applied in EMS.

ii. If the transmission line trips and recloses two times within a 12-hour period, follow the steps below:

1. Turn off reclosing.

2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.

3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:
   - Power Delivery Manager
   - Power Delivery Director

- Power Delivery Vice President
- Or identified delegate.

F. Fire Risk Potential – Yellow Scenario (2): *line trips to lockout with manual reclose by design/delegation*

i. If the use of reclosing is not allowed at the direction of management go to G, otherwise follow the steps below. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Apply a 12-hour Expiring Fire Mitigation Tag in EMS.

b. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning

c. Request a patrol of the line during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Continue to G.

ii. If the transmission line trips and recloses two times within a 12-hour period, follow the steps below:

1. Turn off reclosing.

2. Change the previously applied expiring fire tag to non-expiring fire tag with a note as to why reclosing is off, and when patrol was requested.

3. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

4. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

5. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:

- Power Delivery Manager
- Power Delivery Director
- Power Delivery Vice President
- Or identified delegate.

G. Fire Risk Potential - Yellow Scenario (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 9.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

1. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

2. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

3. Request an immediate line patrol to be conducted and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Power Delivery Manager, Power Delivery Director, Power Delivery Vice President, or identified delegate. Refer to Section 7 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from a Power Delivery Manager, Power Delivery Director, Power Delivery Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur after 5pm, dispatch the following morning unless otherwise directed by management.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with a:

- Power Delivery Manager
- Power Delivery Director
- Power Delivery Vice President
- Or identified delegate.

H. Fire Risk Potential – Orange Scenario (1): *line trips and auto recloses*

i. Turn off reclosing.

ii. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to

retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning

iii. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

iv. After line patrol has been completed, return the reclosing to the pre-event state unless otherwise directed by the:

- Power Delivery Director
- Power Delivery Vice President
- Or identified delegate.

I. Fire Risk Potential – Orange Scenario (2): *line trips to lockout with manual reclose by design/delegation*

i. If the use of reclosing is not allowed at the direction of management go to J, otherwise follow the steps below.

ii. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available.

2. If close is not successful.

a. Go to J.

J. Fire Risk Potential - Orange Scenario (3): *line trips to lockout (with reclosing enabled or after reclosing has been disabled)*

i. Operator shall assess the situation and may also consider items outlined in Section 9.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operation(s) occur too close to

end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data.

b. Once fault location is known and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate line patrol to be conducted and provide the line patrol personnel with the fault information once available.

3. Impact without the ability to sectionalize move to ii.

ii. Gather information for restoration discussion with Power Delivery Director, Power Delivery Vice President, or identified delegate. Refer to Section 9 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iii. Upon receiving approval to test from a Power Delivery Director, Power Delivery Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If not already completed previously, if fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with and approved by the:

- Power Delivery Director
- Power Delivery Vice President
- Or identified delegate.

K. Fire Risk Potential - Red Scenario (1): *line trips and recloses*

i. Turn off reclosing.

ii. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management. iii. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

iii. Return reclosing to the pre-event state after patrol and approval from the:

- Emergency Coordination Center
- Power Delivery Vice President
- Or identified delegate.

L. Fire Risk Potential – Red Scenario (2): *line trips to lockout with manual reclose by design*

i. If the use of reclosing is not allowed at the direction of management go to M, otherwise follow the steps below.

ii. Operator will follow normal operating procedure and test one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available.

2. If close is not successful.

a. Go to M.

M. Fire Risk Potential - Red Scenario (3): *line trips to lockout*

i. Leave line out of service.

ii. Operator shall assess the situation and may also consider items outlined in Section 5.

1. If the assessment indicates no impact, then leave the line out of service.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operation(s) occur too close to end of daylight, data will be pulled when first responder is onsite the next morning.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If there is a generation-customer impact and the line can be sectionalized:

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If fault location is known via SCADA and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or faulted section isolated, continue to the next step.

c. Request an immediate patrol of the line or isolated line section to be conducted and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

3. Impact without the ability to sectionalize move to iii.

iii. Gather information for restoration discussion with the Emergency Coordination Center (ECC), Power Delivery Vice President, or identified delegate. Refer to Section 9 for considerations if not already completed.

1. Was there anything unusual with the operation?

a. If operation appeared unusual, contact relay support to review prior to obtaining approval to test.

iv. Upon receiving approval to test from the Emergency Coordination Center (ECC), Power Delivery Vice President, or identified delegate, the operator will verify reclosing has been disabled and attempt to close one time.

1. If close is successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician to retrieve the data and if the operations occur after 5pm, dispatch the following morning unless otherwise directed by management.

b. Request a line patrol during daylight hours and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

2. If close is not successful.

a. Obtain fault location information if available via SCADA. If the fault information is not available via SCADA, dispatch a meter/relay technician immediately to retrieve the data unless otherwise directed by management.

b. If not completed previously, once fault location is known and the line can be sectionalized, isolate faulted line section, and restore customers and/or generation per Section 11. If line cannot be sectionalized or fault section isolated, continue to the next step.

c. Request an immediate patrol to be conducted on the line or isolated section and provide the line patrol personnel with the fault information once available unless otherwise directed by management.

d. Any further action must be coordinated with the:

- Emergency Coordination Center
- Power Delivery Vice President
- Or identified delegate.

11. PROCEDURE – TRANSMISSION LINE SECTIONALIZING

Generally, sub transmission is a higher voltage supporting the transfer of power over a longer distance to support load service. When a permanent fault occurs on a transmission line providing load service, the power transfer capability is lost but the line can sometimes be sectionalized automatically or manually to maintain load service. In addition, sub transmission lines are generally equipped with protective relays that can provide fault location information which can be used by the operator if the system is not designed to automatically sectionize.

Operating transmission line switches outside a substation have additional considerations. Transmission line switches outside a substation and within an area of identified fire risk will be operated with a load break device such as a multiple bottle interrupter (i.e. TECO-Rupter or Monorupter) or a SF6 interrupter (i.e. LLS-II). A switch with whips and a single bottle is not sufficient to prevent arcing during switching. Switches without an appropriate load break device will require the vegetation around the switch location to be cleared, the area to be watered down and a water truck/wagon on standby prior to the switch being operated.

Deadline switching is also an option if switches do not have a load break device or if weather conditions exist where clearing vegetation and watering will not be effective. If deadline switching activities will create a customer outage longer than five minutes, then customer notification (outbound call) is required prior to performing switching activities.

In the scenario where a transmission line automatically sectionalizes isolating the faulted section of transmission line, there is **NO** need to turn reclosing off on the remaining source(s). Follow the applicable identified fire risk lockout procedure for restoration of the faulted line section.

In the scenario where a transmission line must be sectionalized manually or the auto-sectionalizing scheme failed to operate, the fault location provided by the protective relays shall be used to identify the section of line to be isolated. Field response shall be notified to complete isolation switching of the faulted section prior to patrolling. In the case where an auto-sectionalizing scheme failed to operate, the operator can remotely isolate the faulted section of line. In both these cases, there is **NO** need to turn reclosing off on the remaining source(s).

Additionally, in the event that an energized alternate source is available post event, there is **NO** need to patrol this source prior to utilizing it as part of returning service.

12. NERC EVIDENCE

This document is used as evidence for the following NERC standard requirements when required:

- EOP-011-1, Requirement 1.2.6.

13. TRAINING PLAN

This document will be updated annually prior to System Operations operator spring training. The following departments have been identified to receive training on this policy. For the Instructure Lead training, Document Review is also required.

Organization	Personnel	Method
Grid Operations	Operators	Instructor Lead
Grid Operations	Management	Document Review
Region System Operations	Outage Coordinators	Instructor Lead
Region System Operations	Operators	Instructor Lead
Region System Operations	General Foreman	Instructor Lead
Region System Operations	Management	Document Review
System Operations	Management	Document Review
T&D Field Operations	Field Personnel	Instructor Lead
T&D Field Operations	Management	Document Review
Emergency Management	All	Document Review
Meteorology	All	Document Review
Technical Services	All	Document Review
Real-time Grid Engineering	All	Document Review
Renewables Operations	Operators	Instructor Lead
Renewables Operations	Management	Document Review

APPENDIX 1 – SUB-TRANSMISSION FLOW CHART

Refer to associated SOP-201 Flowchart document.

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A BERKSHIRE HATHAWAY ENERGY COMPANY

Operating Distribution Assets During Identified Wildfire Risk System Operations Procedure, SOP-202

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Operating Distribution Assets During Identified Wildfire Risk System Operations Procedure, SOP-202

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1. SCOPE

PacifiCorp has comprehensive plans for wildfire mitigation efforts designed to reduce the probability of utility-related wildfire ignition and to limit damage to company assets. This system operations procedure (SOP) provides an ignition risk mitigation framework for control center operators when restoring distribution assets (35 kV and below) during identified wildfire risk conditions. This procedure does not override de-energization and restoration requirements outlined in SOP-203 (Wildfire Encroachment) or those associated with a Public Safety Power Shutoff (PSPS).

2. REFERENCES

PAC-1000	Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk
RSO-027	Field Recloser Lockout Policy
RSO-029	Distribution Substation Circuit Breaker Lockout Policy
SOP-200	Operating Bulk Electric System Assets During Identified Wildfire Risk
SOP-201	Operating Sub-transmission Assets During Identified Wildfire Risk
SOP-202	Operating Distribution Assets During Identified Wildfire Risk
SOP-203	Wildfire Encroachment
SOP-204	Emergency De-energization Request Procedure
2D.1	Distribution Relay Setting Guide

3. COMMON ACRONYMS

CFCI	Communicating Faulted Circuit Indicator
ECC	Emergency Coordination Center
EMS	Energy Management System
ESS	Enhanced Safety Settings
EFR	Elevated Fire Risk
FCI	Faulted Circuit Indicator
FHCA	Fire High Consequence Area
OMS	Outage Management System
PSPS	Public Safety Power Shutoff

4. DEFINITIONS

Emergency Coordination Center (ECC) – Is a cross departmental group activated when conditions warrant and led by the ECC Executive. During periods of extreme wildfire risk, the ECC monitors the electrical network and evolving weather conditions, both actual and forecasted; it may also coordinate with the department operations chief for field resources to monitor local environmental and asset conditions.

Enhanced Safety Settings (ESS) – Modes of operation for transmission and distribution operations during times of elevated wildfire risk. This includes adjustments to distribution relays during periods of elevated wildfire risk that are intended to minimize the energy release component through modified protective settings or operational practices and the removal of reclosing functionality on transmission with modified reclosing schemes on distribution assets based on daily wildfire risk thresholds and load restoration requirements. ESS (i.e. EFR, TAG, Reclose Off) modes will vary based on relay type and conditions.

Elevated Fire Risk (EFR) – Programmed relay element on microprocessor based distribution relays intended to minimize energy release through adjustments in protective settings. Refer to Engineering Handbook 2D.1, Distribution Relay Setting Guide, for more information on EFR settings.

Entire Circuit – Is the whole section of powerline(s) (all phases) starting at a substation and extending away from the substation to the end of the line; an entire circuit includes all fused or non-fused tap lines.

Full Outage Patrol – Requires confirmation that all overhead lines downstream of the open device as identified by fault data, including fused taps, have been visually patrolled and are clear and able to be safely energized. Based on fault location, the full patrol could be isolated to an area between devices.

Identified Wildfire Risk – Identified by meteorology based on weather, fuel conditions and historical data.

Relay Data – Includes fault current magnitudes and phase targets (including the type of trip – instantaneous or timed) from a fault that can be valuable for engineering to find fault locations. In addition, an operator can use this information to determine if the device did not operate as designed and can use the fault data to complete a preliminary assessment of fault location using the Monarch spreadsheet. Microprocessor relays operating normally will capture all the data necessary to make these determinations, whereas electromechanical relays will only capture the phases of the fault and whether an instantaneous or time delay trip occurred. Engineers can use fault currents from microprocessor relays to find possible locations of the fault and assist first responders with troubleshooting and step restoration. Engineers will be unable to assist with fault locating with information from electromechanical relays. Relay support may be contacted to evaluate fault data when cold load or inrush may be preventing the circuit breaker from closing.

Tag Modes – A type of ESS mode. Tag mode of operation for distribution circuits during wildfire risk periods are intended to minimize the energy release component through

modified protective settings; this is the same protective state used when crews are working on a hot line. Tag modes do not have a reclose and in most cases are more sensitive (faster clearing) than EFR modes. Exact Tag mode functionality will vary by relay type/settings and conditions.

5. PURPOSE

The purpose of SOP-202 is to provide guidelines for operating distribution assets (35 kV and below) during times of identified wildfire risk. This SOP has been developed to balance risks associated with utility service and wildfire. It implements specific procedures for system operations during times of wildfire risk as identified by meteorology for each of PacifiCorp's operating districts. This procedure focuses on managing risk at the operating protective device level (i.e., circuit breaker, line recloser, etc.).

6. ENHANCED SAFETY SETTINGS RELAY MODES

Per PAC-1000 (Section 10), ESS modes for protective relaying devices will be managed by region system operations in coordination with T&D field operations. Region System Operations will be responsible for tracking the application, status, and removal of applied ESS modes in the system of record. EMS will be the system of record for a devices protective setting status.

Upon receiving direction from region system operations management, the region system operator will activate the ESS mode, either through SCADA or by working with T&D field operations personnel to complete required field modifications. When a device must be set by T&D field operations personnel, the operator shall use the predeveloped relay control tables to place the device into ESS mode and coordinate with T&D field operations personnel for relay picture using EFR Verification Do form once activation is complete. If there are any discrepancies placing a device into ESS mode (i.e., wrong relay identified, not programmed as intended, etc.), the operator shall set the device to Tagged until device settings can be verified and coordinate with T&D field operations personnel for relay picture using EFR Verification Do form.

ESS will remain in place until region system operations management advises a system operator to modify a circuit device ESS mode or return it to normal operation. The region system operator shall modify or deactivate ESS mode on a circuit device via SCADA or by working with T&D field operations personnel to complete the field required modifications. When a device must be set or modified by T&D field operations personnel, the operator shall use the predeveloped relay control tables and coordinate with T&D field operations personnel for relay picture using EFR Verification Do form after modification is complete.

When a device must be modified during or after an outage by T&D field operations personnel, the operator shall use the predeveloped relay control tables. Once the outage is restored, the operator shall coordinate with T&D field operations personnel for relay picture using EFR Verification Do form before leaving the device.

When a device must be modified by T&D field operations personnel for activating or deactivating a Hold (device in EFR going to Tagged or Tagged to EFR), the operator shall use the predeveloped relay control tables and coordinate with T&D field operations personnel for relay picture using EFR Verification Do form. If the device is already in Tagged for ESS purposes and no manipulation of relay is occurring, no EFR Verification Do form is needed.

6.1 EFR Operation Modes on Upgraded Relays – Distribution

The EFR feeder protection scheme is used on overhead or overhead-and-underground combination distribution lines during wildfire risk conditions. This protection scheme can only be implemented on modern microprocessor relays. The scheme may be applied on feeders with or without downstream reclosers. Refer to Distribution Relay Setting Guide 2D.1 for more information on EFR settings.

6.2 ESS Operation Modes on Existing Devices – Distribution

Substation relays and recloser controllers on the system that have not been upgraded to modern microprocessor relays, shall use existing tag and recloser control functions for ESS operation.

7. WILDFIRE RISK POTENTIAL – OPERATIONAL AUTHORITY

As set forth in PAC-1000, region system operations will adjust operational procedures when wildfire risk has been identified by meteorology. The wildfire risk level is expressed using a color-coded system, with five levels:

	Non-Wildfire Operations
	Low Risk
	Elevated Risk
	Significant Risk
	Extreme Risk

Control center operators shall modify system operations, based on the color identified in the weather briefing. The wildfire risk level may modify operational authority for restoring a distribution line or a section of distribution line, as summarized in the following table:

Wildfire Risk Potential	Operational Authority	Comments
Non-Wildfire Operations	Operator	Operator follows normal operating procedures and has normal restoration authority.
Low	Operator	Operator has authority to restore based on lack of identified hazards and favorable weather conditions.
Elevated	Operator or director	Operator has limited authority to restore without patrol based on meeting weather condition criteria or receipt of patrol maps and/or opening pre-identified isolation points. Director can authorize restoration without patrol if weather criteria is not met or without engineering patrol maps and/or opening pre-identified isolation points.
Significant	Director or above	**Operator does not have operational authority to test ORANGE areas without patrol** unless ORANGE meteorology risk or patrol map indicated areas have been isolated. Otherwise, a director in coordination with the operator can use the restoration checklist (Table 2) in Section 8 to determine restoration options.
Extreme	ECC, power delivery vice president, or above	**Operator does not have operational authority to test or re-energize without approval** from the ECC executive, a power delivery vice president (or above), or identified delegate.

Table 1 – Identified Wildfire Risk Level

8. ITEMS FOR CONSIDERATION DURING IDENTIFIED WILDFIRE RISK

8.1 Considerations to Restore After Lockout

The following items may be considered when evaluating the option to test a locked-out circuit breaker or line recloser during restoration. Favorable weather conditions are considered to exist when wildfire risk potential is low, or elevated with relative humidity greater than 50% and wind gusts are less than 10 mph.

Restoration Checklist	YES
In the area of the outage, does PacificorpWeather.com show humidity and wind gusts are favorable?	
Do the favorable weather conditions in the field (discussion with first responder) match that identified on the weather website?	

Is the first responder free of concerns about energizing based on local weather and/or asset conditions.	
Is the site free of identified hazard conditions?	
Have the high fire risk areas been isolated?	
Is a patrol map available from engineer review of fault currents?	
Are there activated FCIs?	
Is the circuit in a normal state?	
Is the circuit located in an urban area?	
Is the terrain of the circuit accessible?	
Is it raining across part of the circuit?	
Is the area free of lightning, based on LightningMaps.org?	
Does current time of day allow for a complete daylight patrol?	
Is the circuit in an FHCA?	
Is the area free of fires?	
Has the circuit been out less than one hour?	

Table 2 – Restoration Checklist

8.2 Considerations to Restore After Wildfire Encroachment Re-Energization

After a wildfire encroachment emergency de-energization, the operator shall follow the re-energization procedures outlined in SOP-203.

9. PROCEDURE – DISTRIBUTION

This section outlines the procedures for the operation of substation distribution circuit breakers, line reclosers, Fusesavers, fuses or other isolation devices when identified wildfire risk conditions are present. An operator must be aware that identified wildfire conditions will vary circuit to circuit, line recloser to line recloser, or isolation device to isolation device. As indicated in Section 4, various devices (i.e., circuit breakers, line reclosers, Fusesavers, etc.) may have some form of an ESS mode applied depending on wildfire risk.

Except for immediately known cause operations, the operator's first step is to send the initial responder to the device site so fault data can be retrieved unless the data is available in EMS. Once the fault data has been received, the operator will provide it to an engineer for fault location analysis. For known cause operations, the region system operator will request fault data to be collected after restoration and sent to engineering to validate modeling accuracy as well as to identify outage location trends.

FCI fault data can also be used to locate a fault on a circuit. In some cases, FCIs have been installed on branch circuits and/or out on the main line and specifically available CFCI information allows the operator to quickly direct the initial responder to the area of potential cause. The operator shall check the CFCI online system (AMPLE) to determine if any fault data is available for the operation under investigation. The fault information shall be communicated to an engineer.

Normal outage notification procedures will be used in all cases when an operation occurs unless specified otherwise below.

Distribution Restoration

Conditions in which a test energization is authorized shall be done using the current wildfire risk color associated ESS Mode.

In all cases, the current wildfire risk color shall take precedence over the mode the device tripped in. If a device will not remain closed due to inrush, cold load, or the system configuration will not support a step restoration process (i.e., there are no points of isolation), an engineer shall be consulted on next steps.

9.1 Device Lockout – DARK GREEN or LIGHT GREEN (NORMAL on EMS screen)

Non-wildfire operating procedures apply, and an operator has operational authority to test without a patrol, sectionalize/isolate and restore, or re-energize after a patrol. Note that the EMS screen will have "NORMAL" in white on a black background when the weather matrix is dark green. If a device locks open and ESS is enabled while in light green, the device may be returned to normal settings during and after restoration.

9.2 Device Lockout – YELLOW

In all cases, the current wildfire risk color shall take precedence over the mode the device tripped in. The operator shall open downstream reclosers before closing the upstream device when circuits have been open for more than three hours.

For devices without ESS mode enabled due to an active exception or in accordance with the activation requirements set forth in PAC-1000, the operator may proceed with normal restoration efforts. If restoration was successful and a patrol was not already completed, the operator shall direct field personnel to complete a mainline patrol. If restoration efforts are not successful, the operator shall begin to step restore and engage engineering when the circuit or portion of the circuit cannot be restored.

When closing a device there is the potential to trip upstream or downstream ESS enabled devices. If necessary, coordinate with engineering to determine the state each device should be in when closing a device.

If ESS mode is enabled on the device based on current wildfire risk color, refer to the relay control table for close operations. If the relay control table is not available and/or the operator is unable to close a device, contact relay support or a real-time engineer for direction. Relay data may be requested to be downloaded by a relay technician.

When a device lockout occurs and ESS mode is enabled, the operator shall consider hazard calls and apply the following conditions before testing:

- Relative humidity is greater than 50% and wind gusts are less than 10 mph

OR

- Isolation point(s) "open" upstream of area(s) identified on engineer patrol map

OR

- Previously identified isolation point(s) are "open" (As tagged in OMS)

OR

- Power Delivery Director (or identified delegate) or above may give approval to proceed

If none of the above sets of conditions are met the operator will begin the patrol and step restore process unless otherwise directed by a power delivery director.

If one set of conditions above is true:

The operator may proceed with restoration efforts including testing without a patrol.

If the test was successful for a risk area identified by meteorology and a patrol was not already completed, the operator shall direct field personnel to complete a patrol of the fault location area(s) identified. If fault location data is not available, field personnel shall complete a full patrol of the circuit downstream of the device that opened.

Isolated portions of a circuit will be patrolled before restoration. Inaccessible areas (i.e., locked gates, areas that cannot be adequately patrolled at night, etc.) will be isolated and restored during daylight hours after the required patrol has been completed unless directed otherwise by a power delivery director.

9.3 Device Lockout – ORANGE

In all cases, the current wildfire risk color shall take precedence over the mode the device tripped in. The operator shall open downstream reclosers before closing the upstream device when circuits have been open for more than three hours.

For devices without ESS mode enabled due to an active exception or in accordance with the activation requirements set forth in PAC-1000, the operator may proceed with normal restoration efforts. If restoration was successful and a patrol was not already completed,

the operator shall direct field personnel to complete a mainline patrol. If restoration efforts are not successful, the operator will coordinate with engineering and begin to step restore.

When closing a device there is the potential to trip upstream or downstream ESS enabled devices. Coordinate with engineering to determine the state each device should be in when closing a device.

If ESS mode is enabled on the device based on current wildfire risk color, refer to the relay control table for close operations. If the relay control table is not available and/or the operator is unable to close a device, contact relay support or a real-time engineer for direction. Relay data may be requested to be downloaded by a relay technician.

When a device lockout occurs and ESS mode is enabled, the operator shall consider hazard calls and apply the following conditions before testing:

- Isolation points "open" upstream of areas identified on engineer patrol map

OR

- Previously identified isolation point(s) are "open" (As tagged in OMS)

OR

- Power Delivery Director (or identified delegate) or above may give approval to proceed

If none of the above sets of conditions are met the operator will review the Restoration Checklist (Table 2) with a power delivery director or identified delegate to determine the restoration actions to be taken.

If one set of conditions above is true:

The operator may proceed with restoration efforts including testing without a patrol except for isolated areas. Otherwise, a power delivery director (or authorized delegate) or above approval is required for restoration.

Isolated portions of a circuit will be patrolled during **DAYLIGHT** before restoration. Inaccessible areas (i.e., locked gates, areas that cannot be adequately patrolled at night, etc.) will be isolated and restored during daylight hours after the required patrol has been completed unless directed otherwise by a power delivery director (or authorized delegate).

If applicable and/or feasible, a drone inspection may be requested.

9.4 Device Lockout – RED

If the identified wildfire risk for a device is RED, then all restoration efforts will be authorized by the ECC executive if the ECC is active, otherwise may be authorized by a

power delivery vice president (or above) or identified delegate. This is true for restoration after proactive de-energization or a device lockout.

For an unknown cause device lockout, the operator will direct the initial responder to obtain relay data from the device, if not available in the EMS, and provide the relay data to the engineer to assist with fault location.

Once the relay data and/or FCI/CFCI data has been received, the operator shall obtain real-time weather observations from the initial responder, which will be evaluated by senior management or the ECC executive.

The operator may direct the initial responder to begin patrolling the circuit but must **WAIT (do not restore)** for restoration direction from a power delivery vice president (or above) or the ECC executive.

Once permission is given to restore, **DAYLIGHT** step restoration process may begin.

10. TRAINING PLAN

This document will be updated annually before system operations operator spring training. The following departments have been identified to receive training on this SOP. For the instructor lead training, document review is also required.

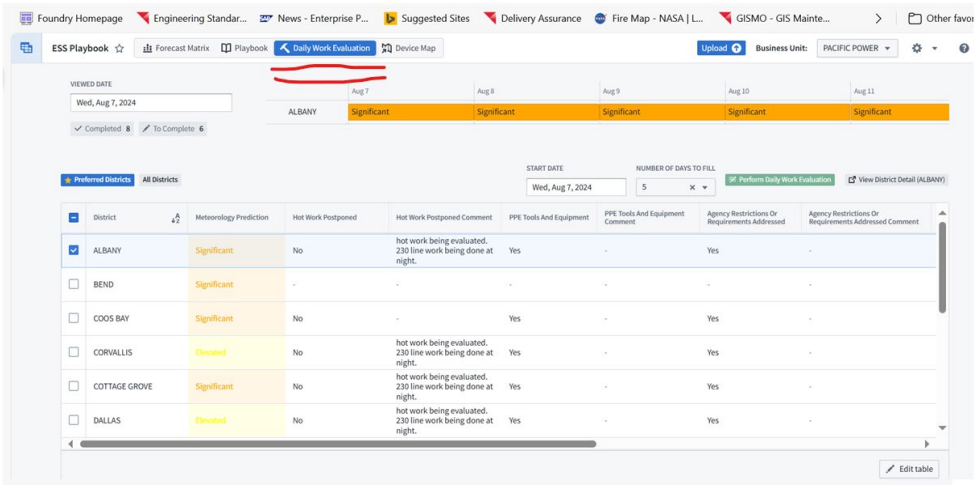
Organization	Personnel	Method
Grid Operations	Operators	Instructor Lead
Grid Operations	Management	Document Review
Region System Operations	Outage Coordinators	Instructor Lead
Region System Operations	Operators	Instructor Lead
Region System Operations	General Foreman	Instructor Lead
Region System Operations	Management	Document Review
System Operations	Management	Document Review
T&D Field Operations	Field Personnel	Instructor Lead
T&D Field Operations	Management	Document Review
Emergency Management	All	Document Review
Meteorology	All	Document Review
Technical Services	All	Document Review
Real-time Grid Engineering	All	Document Review
Renewables Operations	Operators	Instructor Lead
Renewables Operations	Management	Document Review

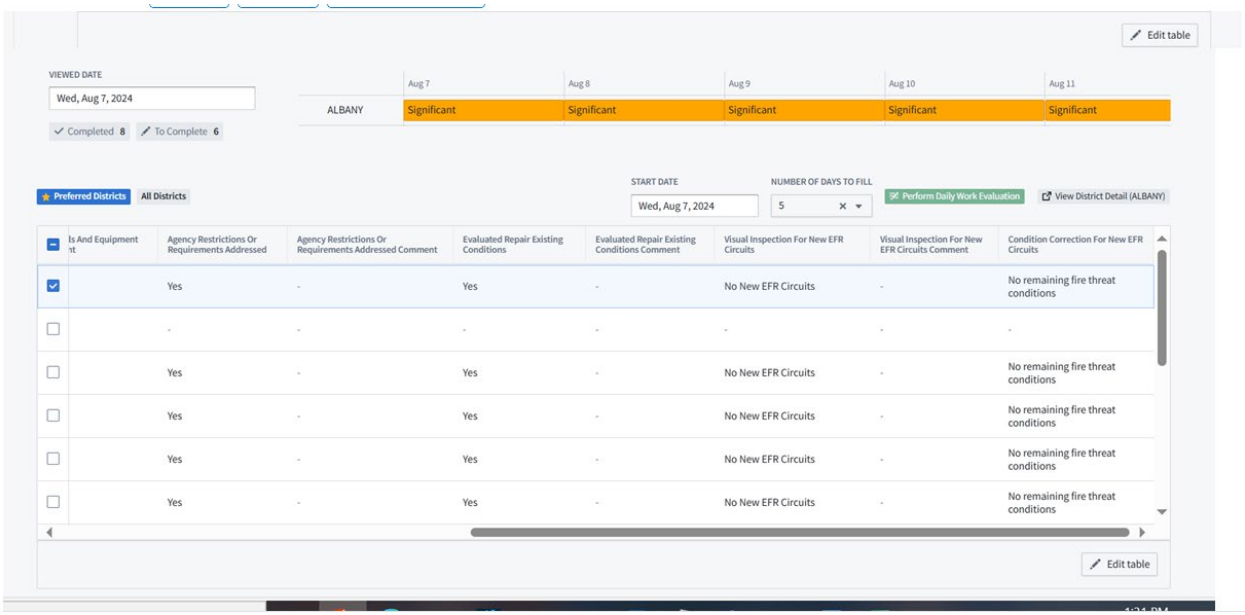
APPENDIX 1 – OPERATOR MATRIX

	Fire Risk of Device		
DISTRIBUTION	**Yellow**	**Orange**	**Red**
Restoration directed by ECC			X
Standard Actions after lock out	X	X	
Get targets and fault currents	X	X	X
Open isolation points if applicable	X	X	
Hazard calls reviewed	X	X	X
If device open > 3 hrs, open downstream reclosers	X	X	X
CB or Recloser trips to lockout	X	X	X
Considerations to energize, 1 group must be met	X	X	X
Humidity > 50%, AND	X		
Wind gusts < 10 mph, AND	X		
OR	X	X	
Engineer patrol map isolation points patrolled or opened	X	X	
OR	X	X	
Fuels risk isolation points patrolled or opened	X	X	
OR	X	X	
Director or above approval to proceed	X	X	
OR			
Power Delivery VP or ECC executive approval to proceed			X
ESS Mode enabled	X	X	
Director approval required to restore		X	
Test with ESS mode enabled	X	X	
Stays closed	X	X	
Full patrol	X	X	
Opens back up	X	X	
Retrieve Fault Data	X	X	
Patrol and Step Restore	X	X	
For isolated portions due to high risk	X	X	
Patrol before restoration	X		
Daylight Patrol before restoration		X	
For inaccessable areas	X	X	
Daylight Patrol before restoration	X	X	
Drone inspection, if applicable		X	

DISTRIBUTION

Example of a Daily Work Evaluation summary record:





PACIFICORP®
A BERKSHIRE HATHAWAY ENERGY COMPANY

Transmission & Distribution Vegetation Management Program

Standard Operating Procedures

Revision 8 – Issue Date: 8/29/2024

Mission Statement:

Our utility Vegetation Management Program is committed to customer service, community safety, enhancing service reliability, and protecting our environment through managing trees and vegetation around our distribution and transmission facilities using professional expertise and industry best practices.

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08	08/29/2024	Tyler Sorensen, RMP Vegetation Management Director, Josh Hooley, PP Vegetation Management Director, Brian King, Director Vegetation Management Support

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1. PROGRAM OVERVIEW

PacifiCorp's Vegetation Management Program seeks to minimize safety and service reliability risks associated with vegetation near overhead distribution and transmission power lines, primarily by pruning or removing trees that could grow into or fall into (when identified as a hazard) the power lines.

When feasible, PacifiCorp prioritizes the removal of tall-growing trees and vegetation to prevent future conflicts with overhead power lines, while supporting the establishment of low-growing species that will never interfere with the high-voltage lines. Considering the interests of property owners and other land use objectives, it is not always possible to remove incompatible trees. Tall-growing trees that cannot be removed must be pruned to maintain clearance around power lines through use of arboriculturally sound pruning practices.

PacifiCorp's Vegetation Management Program utilizes industry best practices, including systematic maintenance, scientifically based pruning, tree removal, tree replacement, cover type conversion, herbicide and tree growth regulator applications, and the use of specialized tools and equipment.

These standard operating procedures (SOP) cover the Vegetation Management Program for both distribution and transmission facilities. These procedures also include program descriptions, specifications, and protocols for customer relations. PacifiCorp's vegetation management department foresters reference and use these SOPs to guide management of vegetation adjacent to and within powerline rights-of-way (ROW) and easements. Most vegetation maintenance on PacifiCorp's system is performed in the field by qualified independent contractors, and these SOPs are binding on all contractors performing vegetation maintenance.

1.1 Applicable References

PacifiCorp contractors are expected to be familiar with and follow applicable standards and best practices.

The following standards and best practices shall be followed:

- *American national standard for tree care standards* revision, redesignation, and consolidation; including:
    - ANSI A300 *American national standard for tree care operations: (part 1) pruning*
    - ANSI A300 *American national standard for tree care operations: (part 9) tree risk assessment*
- ANSI Z133 *American national standard for arboricultural operations – safety requirements*
- Utility Arborist Association Best Management Practices *Field guide to closed chain of custody for herbicides in the utility vegetation management industry*
- International Society of Arboriculture (ISA) *Best management practices – tree risk assessment*

- ISA *Best management practices – utility pruning of trees*

The following standards and best practices should be followed as circumstances allow:

- ANSI A300 *American national standard for tree care operations: (part 7) integrated vegetation management*
- ANSI A300 *American national standard for tree care operations: (part 7 companion publication) tree, shrub, and other woody plant management – standard practices (integrated vegetation management, third edition)*
- ISA *Best management practices – integrated vegetation management*

1.2 Professionalism

PacifiCorp employs a staff of professional Foresters ("**Foresters**") to manage its vegetation program. Foresters on PacifiCorp's system are Certified Arborists and Certified Utility Specialists, by the International Society of Arboriculture (ISA). If not already holding such certifications when hired, PacifiCorp Foresters must obtain them once they are eligible.

Vegetation management contractors performing vegetation maintenance for PacifiCorp shall have an appropriately trained and certified workforce.

- In accordance with ANSI Z133, all personnel working in proximity to overhead conductors at any time are required to hold one of the following designations: Qualified Line Clearance Arborist or Qualified Line Clearance Arborist Trainee.
- Front line managers for the independent contractors retained by PacifiCorp must be ISA Certified Arborists and ISA Certified Utility Specialists and have a Commercial Pesticide Applicator License in the state(s) they manage. These front-line managers are often called supervisors or general foremen in the field and are referred to as "**Supervisors**" in these SOPs.
- A "**Forest Technician**," sometimes referred to as a Consulting Utility Forester (CUF), or Inspector, is a person working for a vegetation management contractor who performs an inspection to identify vegetation maintenance or an audit of completed maintenance. Forest Technicians working on PacifiCorp property are required to have certain levels of experience, certifications, and professional qualifications. Temporarily, for no more than six months, PacifiCorp will allow a Forest Technician with Forest Technician I classification. In all other circumstances, a Forest Technician must have a Forest Technician II classification or higher. The following levels are established for billing purposes and requirements may be modified on a case-by-case basis:
    - Forest Technician I. Required to obtain ISA Arborist certification within six months.
    - Forest Technician II. Minimum of two years arboricultural-related experience or a combination of education and practical arboriculture experience. ISA Arborist certification.

- Forest Technician III. Minimum of three years arboricultural-related experience or a combination of education and practical arboriculture experience. ISA Arborist and Utility Specialist certifications.
- Forest Technician IV. Minimum of three years arboricultural-related experience or a combination of education and practical arboriculture experience. ISA Arborist and Utility Specialist certifications, pesticide applicator license, and ISA Tree Risk Assessment Qualification required.

PacifiCorp also expects vegetation management contractors performing work to respectfully communicate with the public and other external stakeholders. Communication should begin well in advance of work and involve listening to and understanding people's concerns. Crew members should be prepared to answer basic questions and refer more complex issues to their management. Public land managers, property owners, regulators, and civic organizations have interests in utility vegetation management activities. Educating potentially affected parties about the need for, benefits of, and science behind vegetation management can clarify expectations. Work on publicly owned property can involve administrative procedures that take months of advance work, including navigating permit processes and addressing the concerns of specialists who have responsibility for stewardship over public lands. PacifiCorp Foresters will often lead these discussions, and PacifiCorp expects vegetation management contractors to show professionalism when supporting these activities.

2. GENERAL PROCEDURES

This chapter sets forth many general procedures for utility vegetation maintenance, whether on distribution or transmission lines. (See Chapters 5 and 6 for specific procedures applicable to distribution and transmission lines, respectively.) In all circumstances, PacifiCorp vegetation management contractors must be familiar with and maintain compliance with all state regulatory rules, laws, and regulations governing utility vegetation maintenance.

2.1 Safety

The safety of workers and the public should always be given the highest priority. Federal and state requirements governing vegetation management activities shall be followed at all times, including all OSHA requirements. ANSI Z133 (2017 or most current) and OSHA 1910.269 are examples of these requirements. Activities shall be conducted to minimize tree crew and public safety risks. Contractors shall always have appropriate and operative means of communications when working in the field, such as a handheld radio or telephone communication, including a satellite phone or similar means of communication where warranted. If a safety incident occurs, the Contractor shall follow PacifiCorp's incident reporting process.

PacifiCorp's electrical system will continue in normal operations during routine vegetation maintenance, meaning that power lines are energized. Contractors must make their personnel aware of the potential dangers. As indicated above, all personnel must be qualified to work in the vicinity of energized facilities and hold one of the following designations as defined by ANSI Z133: Qualified Line Clearance Arborist or Qualified Line Clearance Arborist Trainee. All personnel must always maintain the minimum approach distances in **Table 2.1**.

Table 2.1. Minimum approach distances for Qualified Line Clearance Arborists and Qualified Line Clearance Arborist Trainees.

Voltage (kV) (Phase-to-Phase)	Minimum Approach Distance			Source*
	Sea Level to 5,000 ft.	5,000 to 10,000 ft	10,000 to 14,000	
0.05-0.300	Avoid contact	Avoid contact	Avoid contact	APM/Z133
0.301-0.750	1′ - 6″	1′ - 7″	1′ - 7″	APM/Z133
0.751-15.0	2′ - 6″	2′ - 7″	2′ - 10″	APM/Z133
15.1-46.0	3′ - 6″	3′ - 7″	3′ - 8″	APM/Z133
46.1-72.5	3′ - 6″	4′ - 0″	4′ - 4″	Z133
72.0-121.0	3′ - 11″	4′ - 6″	4′ - 10″	Z133
121.1-145.0	4′ - 6″	5′ - 2″	5′ - 7″	Z133
145.1-169.0	5′ - 1″	5′ - 9″	6′ - 3″	Z133
169.1-242.0	7′ - 0″	7′ - 11″	8′ - 7″	Z133
242.1-362.0	11′ - 9″	13′ - 6″	14′ - 7″	Z133
362.1-420.0	14′ - 8″	16′ - 9″	18′ - 2″	Z133
420.1-550.0	17′ - 6″	20′ - 0″	21′ - 8″	Z133
550.1-800.0	23′ - 9″	27′ - 2″	29′ - 5″	Z133

* APM is PacifiCorp's *Accident prevention manual* (Joint APM and Grounding Committee), and Z133 is the *American national standard for tree care operations*.

2.1.1 De-Energizing a Line

Minimum approach distances for qualified line clearance arborists shall not be compromised. As indicated in the **Table 2.1**, these clearance distances are drawn from ANSI Z133 and PacifiCorp's *Accident prevention manual* (Joint APM and Grounding Committee). If there is a difference in the distances required in the two standards, the greater of the two is operative. If work requires violating a minimum approach distance, or if circumstances otherwise make work unsafe, the Contractor shall request to de-energize the line.

If, in the judgment of the Contractor, vegetation maintenance cannot be completed safely, the Supervisor shall notify the PacifiCorp Forester and request a "Planned Interruption." A planned interruption allows for line to be de-energized to safely perform required maintenance. This process requires notice of at least 48 business hours to the affected customer(s). The planned interruption process is generally coordinated through a service coordinator at the district office. Customers who will be affected by planned power outages associated with clearances must also receive advance notice of 48 hours, except during emergency situations such as storm restoration work. In general, interruptions of transmission lines require significantly more time to schedule and may require notice of weeks or even months.

2.1.2 Tree on Line

If a tree or tree part accidentally falls onto an energized line, work shall stop immediately. If emergency services are required, a crew member should call 911 immediately. The incident should also be reported immediately to the applicable PacifiCorp control center (**Table 2.2**).

Table 2.2. Control center numbers.

Control Center	Phone Number	Service Areas
PP North	(503) 408-3623	Astoria/Clatsop, OR; Bend, OR; Hood River, OR; Pendleton, OR; Portland, OR; Walla Walla, WA; Yakima, WA
PP Central	(503) 408-3626	Albany, OR; Lincoln City, OR; Casper, WY; Cody, WY; Douglas, WY; Laramie, WY; Rawlins, WY; Riverton, WY; Rock Springs, WY; Worland, WY
PP South	(503) 408-3629	Coos Bay, OR; Crescent City, OR; Grants Pass, OR; Klamath Falls, OR; Medford, OR; Mount Shasta, CA; Roseburg, OR; Yreka, CA
RMP North	(801) 220-6930	Entire service territory

2.1.3 Readily Climbable Trees

Readily climbable trees have low limbs that are accessible from the ground and sufficiently close together so that the trees can be accessed from the ground (without using a ladder, vehicle, or special equipment) and climbed by a child or average person. In addition, a readily climbable tree has a main stem or major branch that would support a child or average person within arms' reach of uninsulated conductor or within proximity to conductor such that the climber could be injured by direct or indirect contact with the line. Readily climbable trees are typically located

near homes, schools, parks, businesses, or other locations that people (particularly children) frequent.

Readily climbable trees pose a safety risk when a trunk or main stem would allow a child or average person to climb within arm's reach of an uninsulated, energized electric line. If a readily climbable tree has grown within such an area, the tree shall be pruned to sufficiently render the tree no longer readily climbable or, if pruning is not feasible, removed.

2.1.4 Tree Houses

Tree houses built in trees growing near power lines present possible electric safety risks. Children or others may contact the line, either directly or indirectly, if a tree house is built too close to conductors. Indirect contact may occur through any conductive object, including a tree or tree parts that are contacting power lines. Minimum tree house distances are set at twice the "Minimum approach distances to energized conductors for arborists not qualified by training and experience to work within 10 feet of electrical conductors" as established in Table 1 of ANSI Z133.

Tree houses built in trees growing in proximity to power lines must meet two criteria to remain where they are located. First, no part of the structure may be any closer than the distance specified in **Table 2.3**. Second, the tree must be pruned sufficiently to maintain the clearance distances specified in **Table 2.3** until the next scheduled work. Maximum line sag and sway must also be taken into consideration. If these conditions cannot be met, the Contractor shall notify customer of condition and attempt to remove the tree house. If a customer refuses, the Contractor shall follow refusal process set forth in Chapter 8 and report such condition to PacifiCorp Forester. As an alternative to removal, facility reconfiguration may be done at a property owner's request and expense.

Table 2.3. Tree house clearances.

Voltage Phase-to-Phase (kV)	Minimum Tree House Distance	
	From Conductors (Ft-In)	Tree Clearance (Ft-In)
≤ 50	20′ - 0″	10′- 0″
50.1-72.5	22′- 0″	11′- 0″
72.6-121.0	25′- 4″	12′- 8″
138.0-145.0	26′- 8″	13′- 4″
161.0-169.0	28′- 0″	14′- 0″
230.0-242.0	33′- 4″	16′- 8″
345.0-362.0	41′- 4″	20′- 8″
500.0-550.0	53′- 4″	26′- 8″
785.0-800.0	70′- 0″	35′- 0″

2.1.5 Fire Protection

Federal, state, and local fire protection laws and regulations shall be followed, and the Contractor performing the work must obtain necessary work permits. Crews shall have all fire suppression tools and equipment required by the responsible governmental agency. Contractors shall also

adhere to fire restrictions concerning work hours, fire watch following work, and other policies of the pertinent jurisdiction. Contractors with crews working in fire-prone rural areas shall provide basic fire prevention and suppression training to their crews annually. Documentation of this training shall be submitted annually to the PacifiCorp Forester by April 30.

2.2 Environmental Respect

Environmental respect is a core value of PacifiCorp, as well as Berkshire Hathaway Energy, the parent company of PacifiCorp. Contractors are required to strictly adhere to all environmental rules and regulations. Moreover, Contractors shall conform to the additional environmental protections contained in these SOPs.

2.2.1 Species of Concern

Vegetation maintenance shall not disturb or harm any rare, threatened, endangered, or protected plant or animal species. Nesting season work restrictions exemplify important scheduling considerations necessary to accommodate protected species. If there are rare, threatened, endangered, or protected plant or animal species present at a location where work is planned, the Contractor must stop work and immediately inform the responsible PacifiCorp Forester.

2.2.2 Wetlands

Federal, state, and local laws and regulations concerning wetlands shall be followed. Wetlands are lands where water saturation is the dominant factor determining the nature of soil development and the types of plant and animal communities present living in and on the soil. If the Contractor has a question about whether an area would be classified as a wetland, the PacifiCorp Forester can confer with PacifiCorp environmental services.

2.2.3 Stream Protection

Federal, state, and local laws and regulations shall be followed concerning riparian area and stream protection. Work shall not pollute water. Trees or tree parts shall not be felled into streams or drainage ditches in a way that could obstruct or impair the flow of water, unless instructed otherwise by the responsible governing agency. If the Contractor has a question about whether an area would be classified as riparian or a stream, the PacifiCorp Forester can confer with PacifiCorp Environmental. Soil or debris shall not be placed below the high-water mark of streams, unless instructed otherwise by a responsible authority. Equipment shall use existing or designated stream crossings.

2.2.4 Bird Protection

Migratory birds are protected by the Migratory Bird Treaty Act of 1918 (16 USC 703-712) (MBTA). Most bird species are protected under the MBTA; therefore, in an abundance of caution, all bird species should be considered subject to the law's provisions. The Contractor shall conduct vegetation maintenance consistent with the MBTA.

The MBTA prohibits removal of bird nests that have eggs or chicks and killing any birds which are members of any protected species. Active nests may not be disturbed, unless the responsible

PacifiCorp Forester, after consultation with PacifiCorp environmental services, has provided authorization. If tree crews identify a possible immediate risk (e.g., active nest in the vicinity of vegetation listed for work), the Contractor shall contact the PacifiCorp Forester. Foresters will consult with PacifiCorp environmental services regarding whether or not work may proceed. If work is postponed until after young have left the nest, the location must be recorded and tracked to ensure completion at the appropriate time.

The nests of eagles, threatened and endangered species, and colonial waterbird nests (such as those of herons) may not be disturbed – whether or not they are active. Eagles are subject to additional protection; it is illegal to disturb them near their nests or winter roosting sites. If large stick nests, suspected to be protected nests, are in vegetation identified for removal, the Contractor must contact the PacifiCorp Forester who will consult with PacifiCorp environmental services.

Raptors (birds of prey) and herons require buffers (**Table 2.4**) around active nests to prevent them from being disturbed, unless instructed otherwise by PacifiCorp environmental services or applicable regulatory authority.

Table 2.4. Work buffers around active nests of eagles, hawks, and herons.

Species	Work Buffer*
Bald Eagles (Jan 1-Aug 31)	660 feet
Bald Eagle roosts (Nov 1-Mar 31)	0.25-mile
Golden Eagles (Jan 1-Aug 31)	0.25-mile
Hawks (exceptions below)	600 feet
Ferruginous hawk	0.5-mile
Northern goshawk (Mar 1-Aug 31)	0.5-mile
Swainsons hawk	0.25-mile (CA: 0.5-mi)
Owls	300 feet
Great Gray Owl	0.25-mile
Northern Spotted Owl*	0.25-mile
Osprey	600 feet
Herons/Colonial Nesters	600 feet
Songbirds	50 feet

*Buffers may be modified on a project basis if: (1) a regulatory agency stipulates a different requirement; or (2) if vegetation management work results in agitated behavior of birds, work should be stopped and PacifiCorp environmental services should be contacted for guidance; or (3) a nest is active or inactive outside of the typical buffer dates.

In general, if a bird leaves a nest and does not return within an hour, it is being disturbed and the buffer should be increased. In these cases, PacifiCorp environmental services should be contacted within 24 hours to monitor the nest and respond appropriately if the adults fail to return.

Active bird nests and inactive eagle nests should be reported to the appropriate Forester and environmental services using the procedure outlined in **Figure 2.1**.

Anyone working in vegetation management who encounters a dead bird near or adjacent to PacifiCorp facilities (e.g., near a pole or under conductor within the ROW) should report it to environmental services.

Figure 2.1. Bird nest procedure.

2.2.5 Spills

Every effort should be made to prevent a spill from occurring. All trucks or equipment that carry or transport chainsaw gas, bar oil, hydraulic fluid, herbicide, or any other liquid that can be impactful to the environment shall have an appropriate spill kit.

2.2.6 Archaeological Sites

Vegetation management activities shall not disturb archeological sites. If a Forest Technician or tree crew identifies something that might have archeological significance, they shall leave the site and contact the PacifiCorp Forester. The Forester should contact PacifiCorp environmental services for advice on whether or not to continue. Work should not proceed without authorization from PacifiCorp environmental services.

2.3 Communication

The Contractor shall report any vegetation conditions that are imminently likely to cause a transmission or distribution outage. Specific to transmission, all vegetation maintenance workers must comply with transmission grid operations operating procedure PCC-215*, Guidelines for communication of vegetation conditions that present an imminent threat of transmission line outage,* which is designed to meet Requirement 4 of the North American Electric Reliability Corporation (NERC) FAC-003-5 *Transmission vegetation management* standard.

Requirement 4 instructs utilities to notify the control center with switching authority for the applicable line of vegetation conditions that is likely to cause a fault at any moment. PacifiCorp may implement temporary actions, such as rating reductions or taking transmission lines out of service until vegetation can be cleared. If vegetation is identified as likely to cause a fault at any moment, the Contractor shall immediately contact the PacifiCorp Forester. Inspectors should report the exact location of the subject trees (providing longitude and latitude if possible) as part of the process.

2.3.1 Media

Requests from the media (print, electronic, radio, or television) shall be referred to PacifiCorp external communications and the regional business manager responsible for the area in which the request was made.

2.3.2 Legal

If personnel performing vegetation maintenance is approached by an attorney or otherwise notified of any legal proceedings, the Contractor shall notify the responsible PacifiCorp Forester, who will notify PacifiCorp's general counsel's office.

2.4 General Requirements Applicable to All Vegetation Maintenance

The subsections below apply to all utility vegetation maintenance, performed for PacifiCorp. There are additional specifications for maintenance on different voltage power lines, with separate chapters for distribution lines (Chapters 5) and transmission lines (Chapter 6).

2.4.1 Tree Removal

In certain circumstances, it is necessary or appropriate to remove trees (i.e., remove the threat posed to electrical infrastructure or remove the tree from the "inventory" of future work). When a tree is removed, the stump shall be cut to within 6 inches of the ground or as close to it as practical (for example, at the top of a barbed wire fence that has become imbedded in the trunk).

Stumps of all deciduous trees, brush, and vines that are removed shall be treated with an approved herbicide, unless otherwise indicated by landowner or restricted by the land managing agency. Tree removal may be discretionary, or necessitated by the presence of Hazard Trees.

- Hazard Trees. "**Hazard Trees**," are defined as a tree in whole or in part, that might fail, and which is identified as a likely source of harm. Trees that are dead, dying, diseased, deformed, or unstable, which have a high likelihood of falling and contacting a specific target (electrical infrastructure) should be assessed for removal. The Contractor shall conduct a Level 1 visual assessment, and where necessary, a Level 2 assessment, consistent with ANSI A300. Hazard Trees pose a safety and reliability risk and must be removed (or pruned to the extent that the tree is no longer a Hazard Tree). Federal and state agencies sometimes request that trees subject to removal be topped to create "wildlife trees." PacifiCorp may honor such requests, provided the safety of the tree workers or the integrity of facilities are not compromised. Any Hazard Trees removed to accommodate this request should be reduced to a height so that the tree would never contact any PacifiCorp facilities should it fall.
- Discretionary Tree Removal. Discretionary tree removal reduces the total tree inventory and can, therefore, reduce long-term risks to safety and reliability; improve access to facilities, clear lines of sight, and moderate future workloads. In general, removals of trees near powerlines are encouraged and are to be pursued by the Contractor. Additional scope of discretionary tree removals may be included in a particular Work Release.

2.4.2 Mechanical Control Methods

Mechanical equipment such as, Slashbusters®, mowers, jarraffs, helicopter cutters, etc. have the potential to increase productivity and reduce costs in rural, densely vegetated areas. This equipment may be used wherever practical. When using mechanical equipment, the Contractor must comply with all federal, state, or local rules and regulations before equipment use. Contractors are expected to identify opportunities for use of mechanical control and coordinate with PacifiCorp Foresters.

- Mowers and Slashbusters. Mowers and Slashbusters are often more cost-effective than manual methods of tree removal and should be used where terrain and vegetation conditions warrant.
- Helicopter and Other Mechanized Cutters. Helicopter and other mechanized cutters can improve productivity in rural, densely vegetated areas. Mechanical cutting shall comply with ANSI A300 *Tree care standards* Section 5.5.22. Mechanical cutting is typically limited to rural or remote locations. When mechanical cutting is employed, cuts should be made close to the main stem, outside of the branch bark ridge and branch collar. Precautions are taken to avoid stripping or tearing of bark or excessive wounding.

2.4.3 Debris Disposal

Before leaving a particular worksite, all debris must be brought to ground, with no severed limbs left in the tree canopy (hangers). Work locations shall be left in a safe and orderly condition at the end of the workday. "**Debris**" is cut vegetation remaining after maintenance operations.

Debris greater than 6 inches in diameter should be cut into manageable pieces and left on site. Debris less than 6 inches in diameter should be disposed of.

Debris is typically disposed of in multiple ways. First, debris may be chipped using a mechanical chipper and then transported off-site. Second, debris may be chipped using a mechanical chipper and then broadcast on-site in a manner such that no piles of chips greater than 6 inches are created. Third, debris may be lopped into maximum lengths of 3 feet and scattered (if necessary to pile debris, piles shall be no more than 18 inches high). The appropriate method of disposal depends on the area where vegetation maintenance is being performed. Additional debris management requirements may be identified by land managing agencies.

- Developed Areas. In developed areas on landscaped properties (which typically includes all urban areas), cut debris must be chipped and removed from the site unless an agreement has been reached with the property owner to leave it. Debris may be left temporarily, provided the crew has notified the property owner or tenant, and arrangements have been made to clean it up to the property owner's reasonable satisfaction.
- Undeveloped Areas. In undeveloped areas that are not landscaped (typically rural), debris can be chipped and broadcast on-site. In situations where debris will be removed, debris may be left temporarily, provided the crew has notified the property owner or tenant, and arrangements have been made to clean it up to the property owner's reasonable satisfaction.
- Inaccessible Areas. In remote off-road areas without reasonable vehicle access, debris can be disposed of on-site. Use the lop and scatter method mentioned above.

2.4.4 Emergency Response

Tree work will be required from time to time on emergency storm restoration. All storm work must be conducted as if the line is energized. If the line cannot be worked safely under the assumption it is energized, it must be grounded in accordance with Section 2.1.1.

During an emergency response, the scope of work is established by specific instructions from district operations managers in cooperation with PacifiCorp Foresters.

The Contractor shall provide a designated contact person for each region. Requests for crews during an emergency response are routed through that contact who will coordinate with the PacifiCorp Forester and PacifiCorp operations as needed. The Contractor shall be responsible for dispatching crews whenever emergency restoration services are needed.

Notification to customers/landowners is not required during emergency restoration work and crews should conduct themselves respectfully. In general, landowners are responsible for disposal of the debris from trees and limbs falling during storms, because the trees and limbs fell as a result of the storm (not because of routine maintenance). Clean-up and additional pruning work may be appropriate, as directed by a PacifiCorp Forester.

2.4.5 Pronounced Facility Conditions

While the Contractor is not expected or required to inspect electrical equipment, Contractor personnel can be helpful in identifying pronounced equipment conditions, such as cracked poles,

broken crossarms or insulators, loose guy wires, and other problems. Any such condition should be reported to the PacifiCorp Forester, who will report it to operations.

2.4.6 Property Damage

The Contractor shall be responsible for any and all property damage arising out of or related to work performed by the Contractor. The Contractor shall inform PacifiCorp of claims within 24 hours of damaging the property. The Contractor has 15 business days to resolve any damages. If a damage claim is not resolved within 15 business days, PacifiCorp may settle the claim and bill the Contractor.

2.4.7 Freelance Work

The Contractor shall not solicit or perform arboricultural-consulting or tree work (pruning, removal, insect or disease control, fertilization, etc.) for interests outside of officially authorized PacifiCorp projects on open circuits, grids, transmission projects, tickets, storm orders, work orders, or other PacifiCorp assigned projects. Contractors are prohibited from hiring or otherwise compensating persons employed in PacifiCorp's vegetation management department for such freelance work.

2.4.8 Fences and Gates

Gates should be left open or closed as they were found, or as the property owner instructs. Damage to fences or gates shall be reported to the property owner and repaired as soon as possible.

2.4.9 Climbing Spurs

Climbing spurs shall not be used when climbing to prune trees.

Exceptions:

- When ascending a tree, the limbs are more than throw-line distance away and there is no other safe means of climbing the tree
- When the bark is sufficiently thick to prevent spur damage to the cambium
- During tree removal operations

2.4.10 Winching Vehicles

Winch cables or ropes should not be wrapped directly around anchor trees. Doing so damages a tree's bark and cambium. If the need arises to winch a vehicle (including an all-terrain vehicle), a nylon strap (or equivalent) at least 2-inches wide shall be used around the tree, and cables or ropes attached to the strap. Utility poles or towers shall not be used as winch anchors.

3. TREE BIOLOGY AND PRUNING

Understanding fundamental tree biology is essential to understanding the impacts of pruning on tree health and growth (Gilman 2012). Trees in proximity to electrical conductors should be pruned for clearance in a manner that minimizes residual harm to the tree and directs future growth away from the conductors.

3.1 Tree Biology

Utility pruning of trees should incorporate industry best practices that promote healthy tree biology.

3.1.1 Foliage

Tree survival depends on an adequate supply of carbohydrates produced by the leaves. If a tree abruptly loses a large portion of its foliage, as can happen with over-pruning, it could lack the energy resources to meet its needs. Trees with insufficient foliage could be weakened to the point where they become subject to attack by opportunistic insects, disease pests, and sun damage (Shigo 1986; Gilman 2012).

3.1.2 Stems

Trunks and branches are tree stems. Stems make up the bulk of the mass of a tree. Their function is support; energy storage; and water, mineral, carbohydrate and growth regulator transport. A developmental process unique to tree stems is their ability to compartmentalize or "wall off" injury and decay (Harris, Clark, and Matheny 2004). Understanding the anatomy of tree stems is critical in achieving the pruning objective while minimizing damage to the tree.

3.1.2.1 Xylem

"**Xylem**" is wood tissue. Sapwood is young, living xylem that stores carbohydrates, provides support, and conducts water and essential elements. Heartwood is older, dead xylem that provides support, and often contains antimicrobial compounds.

Long, hollow conducting cells (tracheids or vessels) predominate xylem structure. While trees need this vascular structure to conduct water and essential elements, it can be exploited by pathogens to spread disease up and down the stem. Trees attempt to block or "wall" off disease spread by plugging cells in the xylem in a process known as tylosis. (Shigo 1986).

3.1.2.2 Cambium

The tree's "**cambium**" consists of a thin layer of rapidly dividing cells around the outside of the sapwood. Its primary function is to produce wood on its inside, creating diameter growth. This is the only source of wood production in the tree system; the tree has no ability to replace damaged or decayed wood.

Pathogens gain access to wood through wounds. In response to wounding, the cambium generates a "barrier zone" containing antimicrobial compounds. It protects new wood by separating it from potentially infected wood that existed at the time of wounding.

Figure 3.1. The cambium creates a barrier zone that contains discoloration and decay in the old wood.

3.1.2.3 Branch Collars

Branch collars are a combination of parent stem and branch tissue generated through coordinated growth around the branch attachment. (See **Figure 3.2**.) In spring, diameter growth begins at branch tips, and works toward the base. When new branch wood meets the branch base, it grows around the juncture. Later in the growing season, wood from the parent stem envelops branch wood laid down earlier. The "**branch bark ridge**" is area of raised bark where branch wood meets stem wood, pushing the bark outward, forming a layer of raised bark, which is often a sign of a strong branch attachment. The abundance of metabolically active tissue at the branch collar can be made to produce antimicrobial compounds in response to infection. (Shigo 1986). This area is known as the "**branch protection zone**," which is an area of chemically and physically modified tissue within the base of the branch that inhibits the spread of decay from the branch to the parent stem.

Figure 3.2. Branch collars form at the base of branches.

3.1.2.4 Codominant Stems

Codominant stems are stems that are at least half the diameter of their parent stem and compete for dominance in the tree crown (Gilman 2012). They are similar to branches but have no branch collars or branch protection zones making them more prone to decay if one of the stems is removed. Codominant stems are often problematic because as the two crowded branches grow in diameter, they push against each other and undermine the structural integrity of the union, making them prone to stem failure. (Lilly 2010).

3.2 Utility Tree Pruning

Utility tree pruning is a critical practice that balances the need to maintain safety, reliability, and environmental sustainability around utility infrastructure.

Pruning to clear conductors shall adhere to the principles of modern arboriculture. The ANSI A300, ISA *Best management practices: tree pruning*, *Best management practices: utility pruning of trees,* and *An illustrated guide to pruning* (Gilman 2012), among other references, convey those principles.

While proper utility tree pruning should be consistent with practices that promote tree health, utilities cannot place tree health over public welfare. Sometimes, there is no way to obtain proper clearance in a way that ensures a tree's health. (Lilly 2010). This is particularly true regarding foliage retention. In cases where the tree cannot be pruned without harming its health, tree removal is typically best for the tree, tree owner and utility.

3.2.1. Natural Target Pruning

Natural targets are proper final pruning cut locations at strong points in the tree's disease defense system. Natural targets are branch collars and proper laterals. Removing branches at natural targets rarely damages the joining trunk or limb. (Gilman 2012). The ISA *Best management practices: tree pruning,* and ANSI A300 describe the technique. Targets vary depending on whether a branch is removed or reduced.

3.2.2 Directional Pruning

Directional pruning is natural target pruning applied to redirect tree growth away from utility lines (Gilman 2012). ANSI A300 and ISA's *Best management practices* (Kempter 2004) instruct that pruning to clear the utility space involves thinning cuts: removing at natural targets entire branches that are growing toward (or once cut will produce sprouts that will grow toward) the power lines.

While heading cuts produce sprouts that grow quickly back into the power lines, branch removal and reduction promote growth away from conductors. Because one objective of utility pruning is to train trees away from power lines wherever practical, branches growing away from the electric facility should not be pruned. Instead, these stems should be allowed to develop to their natural height or length, provided that growth does not create unreasonable safety risks. This cannot be accomplished with strongly excurrent trees trapped directly beneath conductors.

Topping, round-overs, flush cuts, branch tipping, and rip cuts are improper as they result in damage to the trees. Directional pruning is consistent with natural tree structure. Remaining branches retain their taper, strong attachments, growth regulators, and spacing. They continue to grow and function normally, allowing the tree to reach to its natural height.

"V" shapes often result on properly pruned trees growing under power lines, particularly on decurrent, deciduous trees (Gilman 2012; Kempter 2004; Miller 1998; Shigo 1990). Limbs growing upward and toward the facility should be cut back to the trunk or to limbs growing away from the conductors. Remaining branches should have sufficient clearance, so they do not damage the conductors in inclement weather common for the locality (high wind, freezing rain, snow, or other conditions). Excurrent trees (such as many conifers) are more problematic but should be reduced to appropriate laterals or whorls. "L" or one-sided shapes often result on properly pruned trees to the side of conductors (Shigo 1990; Gilman 2012). Limbs on the wire side of trees located adjacent to facilities should be cut back to the trunk; or to limbs growing vertically, sideways or downward; depending on the distance to the line or available natural target.

Figure 3.3 "V" or "L" shapes can develop from crown reductions on trees growing in close proximity to power lines. The ultimate objective is to train the tree up and away from the conductor whenever possible, so the facility is cleared while minimizing health risks to the tree.

3.2.3 Collar Cuts

Branches should be removed at the edge of the collar. (See **Figure 3.4**.) Cutting into the collar, known as flush cutting, compromises the branch protection zone and creates a direct port of disease entry into the parent stem. Flush cuts are damaging and inappropriate.

Disease can weaken stems, potentially creating safety risks. On the other hand, proper branch removal does not leave stubs that pathogens can use as an energy source to overcome the tree's defense system and spread into the trunk. If the branch is removed correctly, only the branch protection zone is exposed, giving an advantage to trees in keeping out disease. As a result, collar cuts virtually prevent decay from entering the parent stem (Gilman 2012). Occasionally, branch collars are not readily evident, and the collar must be approximated using the branch bark ridge. The cut should start in the branch crotch, just outside the branch bark ridge and follow an outward angle that mirrors the inward angle the branch bark ridge makes with the trunk or parent stem. The cut should end roughly opposite the bottom of the branch bark ridge.

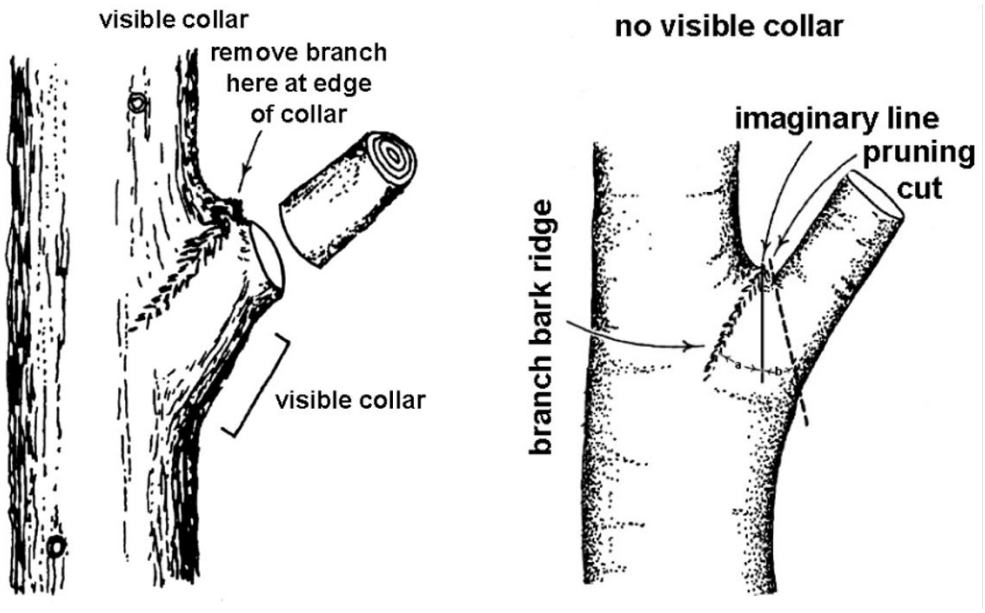

Figure 3.4. A proper collar cut, on a tree with and without a visible branch collar (Gillman 2015).

3.2.4 Reduction Cuts

Reduction is selective pruning applied to reduce the top or side of a tree or individual limb (ANSI 2023). In a utility context, the goal of reduction is to promote future tree growth away from the conductors, at least on decurrent trees. Reduction cuts shorten leads to appropriate laterals (**Figure 3.5**). An appropriate lateral is no less than one-third the diameter of the original limb and retains at least three-quarters of the lead's foliage (ANSI 2023). Individual branches are autonomous in their energy requirements. Removing too much foliage from a limb could deprive it of sufficient energy to establish apical dominance, maintain its taper, close the wound, and compartmentalize disease that could enter the wound.

A lateral that is too small will not develop into a structurally viable leader. Moreover, shortening a lead removes apical meristems and other points of growth regulator production, which can disrupt orderly growth. If, for example, auxin concentrations are insufficient, on some species a crowded mass of upright, rapidly growing, poorly attached shoots can sprout from the cut and grow directly back into the lines.

Removing more than 25% of foliage from a limb has the same damaging result as internodal topping cut, regardless of whether or not the cut is made to a proper-sized lateral. Even under the best circumstances, reduction cuts are potentially harmful, acting more like a heading than a thinning cut (Gilman 2012). Consequently, if a lead cannot be shortened to a limb at least one-third the diameter of the original lead, or if a cut removes more than 25% of the foliage, that limb should be either targeted for removal, or not pruned.

Figure 3.5. A proper reduction cut.

3.2.5 Large Branches

Large branches (those 3 inches in diameter or greater) can seldom, if ever, be removed without harming the tree, particularly if they are codominant stems. Yet, large branches must be prevented from growing toward the utility space; that can mean heading or removing them entirely. Both options can be harmful to the tree, and heading large branches often fails in effectively clearing the conductors. (See **Figure 3.6**.)

Figure 3.6. Old heading cut. Shoots that proliferate from these cuts often dominate the tree's crown. Proper pruning techniques, such as making cuts at the correct location and avoiding over pruning can minimize the formation of epicormic shoots and maintain the tree's natural structure and health.

Removal of large branches should be done using a measured approach. For example, one or two large limbs might be removed out of three that are growing toward the conductors, and the remaining limb(s) subordinated and targeted for removal on subsequent cycles, so long as the required specification clearances are accomplished. Large branches selected for later removal can be subordinated or removed gradually over subsequent cycles (either interim or cycle). Subordination thins a portion of a limb's foliage. Reducing a fraction of the foliage in this way suppresses the stem's growth and allows the remaining tree parts to adjust and develop. In some cases, subordination can allow a codominant stem to develop into a branch over time, enabling a branch protection zone to form so a limb can be removed without unnecessarily subjecting a tree to disease (Gilman 2012). Using subordination over multiple cycles to remove large branches can reduce the effect of structural limb removal on tree health, while ultimately circumventing the permanent problems heading cuts can cause, even if that means temporarily heading the branch.

3.2.6 Heading Cuts

A heading cut is an internodal cut on a stem, or a cut made to a lateral too small to assume dominance and should be considered a "cut of last resort." Removing large stems that have been headed often leaves wide gaps in the tree, because shoots that proliferate from the old heading cuts often dominate the crown, and gaps result when branches containing these shoot clusters are removed. Moreover, previously headed branches usually lack natural targets. When such branches are growing toward the conductors, there might be no alternative but to remove them entirely. However, in some cases, headed limbs may be left as a temporary measure. Such headed branches should be removed on subsequent cycles.

Headed branches growing away from the facility space should not be pruned as a matter of standard practice. However, shoots growing from the old heading cuts should be inspected for structural integrity during subsequent visits. Corrective action, such as crown restoration, could be necessary if these sprouts are found to be structurally weak (Gilman 2012). Crown restoration involves restoring a previously headed stem's natural structure by thinning sprouts emanating from the old wound. Crown restoration should be done incrementally over the course of several cycles. In some cases, structural defects resulting from heading cuts are so severe that they cannot be corrected (Dahle et al. 2006). In these cases, the customer should be contacted about removing the entire tree, or at least the subject branch or branches. If tree or branch removal is not possible, there could be no choice but to remove the weak growth with a new heading cut. This should be done only when extensive decay or hollow exists in the remaining branch, with the approval of the Forester, for safety (not aesthetic) purposes.

3.2.7 Deciduous Trees

The "V" in many crown-reduced deciduous trees quickly fills in with shoots. These shoots eventually require pruning to prevent them from interfering with the lines. In subsequent cycles, it is important <u>not</u> to strip all these sprouts away, since that practice contributes to lion's tailing and can stimulate resurgent growth in many species. Rather, about half of the shoots should be removed and the other half retained, so long as adequate clearance is maintained.

Figure 3.7. On return visits to "V-Outs," under pruning should leave the smaller, suppressed shoots to retain foliage and soften the visual effect of crown reduction.

Shoots selected for removal should be the largest and most vigorous, leaving smaller sprouts behind. Growth selected for retention should be pencil-thin at the point of attachment. If necessary, these remaining shoots may be headed back to obtain specification clearances. In this way, a rotation can be established where the largest, most vigorous shoots are removed each cycle, but smaller, suppressed shoots are left to soften the negative visual effect that many customers find objectionable.

Leaving shoots in the interior of a "V" provides shade and retains auxin production, both of which suppress vigorous sprouting, and helps the trees hold clearance. Eventually the sides of the tree will exceed wire height, resulting in more of a "U," and shade the interior of the tree, suppressing shoot growth even more. In time, this top growth decreases the proportion of the crown occupied by the cleared utility space and softens the negative aesthetics.

Figure 3.8. Crown reduction on a conifer.

3.2.8 Conifers

Many conifers; such as pine (*Pinus spp.*), spruce (*Picea spp.*), and Douglas-fir (*Pseudotsuga menziesii*) have strong central leaders (excurrent form). When these types of trees grow directly under the lines, they should be reduced to the whorl or largest available lateral that provides specification clearance. Cuts made to conifer whorls are typically flat-topped to avoid damage to any branches in the whorl (**Figure 3.8**). Laterals should be tipped on conifers, which prevents them from bending up toward the conductor.

3.3 Tree Growth Rates

Professional judgment and experience is exercised when classifying tree growth rates. Slow-growing trees generally grow vertically less than 1 foot a year. Moderate growing trees generally grow vertically between 1 and 3 feet a year. Fast-growing trees generally grow vertically more than 3 feet a year. While trees exhibit species-specific growth rates, they can also be affected by short-term weather events and local site conditions.

3.4 Integrated Vegetation Management

"**Integrated vegetation management**" (IVM) is a comprehensive method of vegetation management used in certain locations, when possible. IVM is a system of managing vegetation in a manner designed to establish desired vegetation characteristics, such as sustainable plant communities that are compatible with the electric facilities over the long-term.

Desired plant communities are stable, low-growing, compatible with conductors, diverse, and establish a sustainable supply of forage, escape, and nesting cover, movement corridors for wildlife, reduced fire risk, and more open access to the line (Yahner and Hutnik 2004). By establishing and maintaining native vegetation, the invasion of noxious weeds into the corridor is minimized. (Bonneville Power Administration 2000.) If IVM can be established in an area, it also minimizes ground disturbances in the ROW, because of reduced vegetation management activities.

In practice, IVM is often aspirational. It is infeasible to implement IVM in many locations, because of conflicting property rights or other factors. In short, many adjoining property owners are extremely opposed to the loss of tall trees on their properties. Nonetheless, PacifiCorp prefers to use IVM when feasible because of the long-term benefits in this approach. And even when not feasible in all its facets, considerations around IVM help inform other aspects of PacifiCorp's approach towards vegetation management. For example, removal of volunteer saplings is one concrete measure that helps promote IVM principles.

3.4.1 IVM Control Methods

Until optimal plant communities are firmly established, IVM generally requires active intervention to promote preferred vegetation patterns. Control methods are the processes used to achieve IVM objectives. Control methods selection should be based on pre-control evaluations, expected growth rates, line priority, economics, regulations, and specified objectives. Control method types include biological, chemical, cultural, and physical. Reference ANSI A300 (Part 7 companion publication; Miller 2021).

3.4.2 Wire Zone, Border Zone

Properly managed wire and border zones in linear corridors not only effectively protect the electric facilities, but also can become an asset for forest ecology and forest management. (Bramble et al. 1991; Yahner and Hutnik 2004.) In general, the "**wire zone**" is the section of utility transmission ROW between the outside phases, extending outward from the conductors 10 feet. The "**border zone**" is the remainder of the ROW running parallel to the wire zone. The "**outer zone**" is the area outside of the ROW.

Vegetation in the Wire Zone and Border Zone. Species of trees that could grow into the wires at any time in their lives are always discouraged in both the wire zone and the border zone. In general, low-growing and low-volume vegetation is encouraged in the wire zone (e.g., grasses, legumes, herbs, ferns, and low-growing shrubs under 5 feet at maturity). This approach generally facilitates visibility and accessibility for patrols. It also mitigates against the risk of damage to the conductors if there is a fire under the lines. In the border zone, vegetation is managed to

establish compatible plant communities with a maximum height that is well below any required clearance distances. In practice, IVM does not require strict linear dimensions on the ground, because IVM is employed to encourage compatibility where it is possible to implement. Nonetheless, the linear concepts of wire zone and border zone help visualize and explain how IVM is implemented on the ground. Such areas are influenced by topography.

Flat Terrain. On flat terrain, the wire zone is the ROW portion directly under the wires and including 10 additional feet to the field side of the outside phases. The border zone is the area, on both sides of the line, from the edge of the wire zone to the edge of the ROW (**Figure 3.9**).

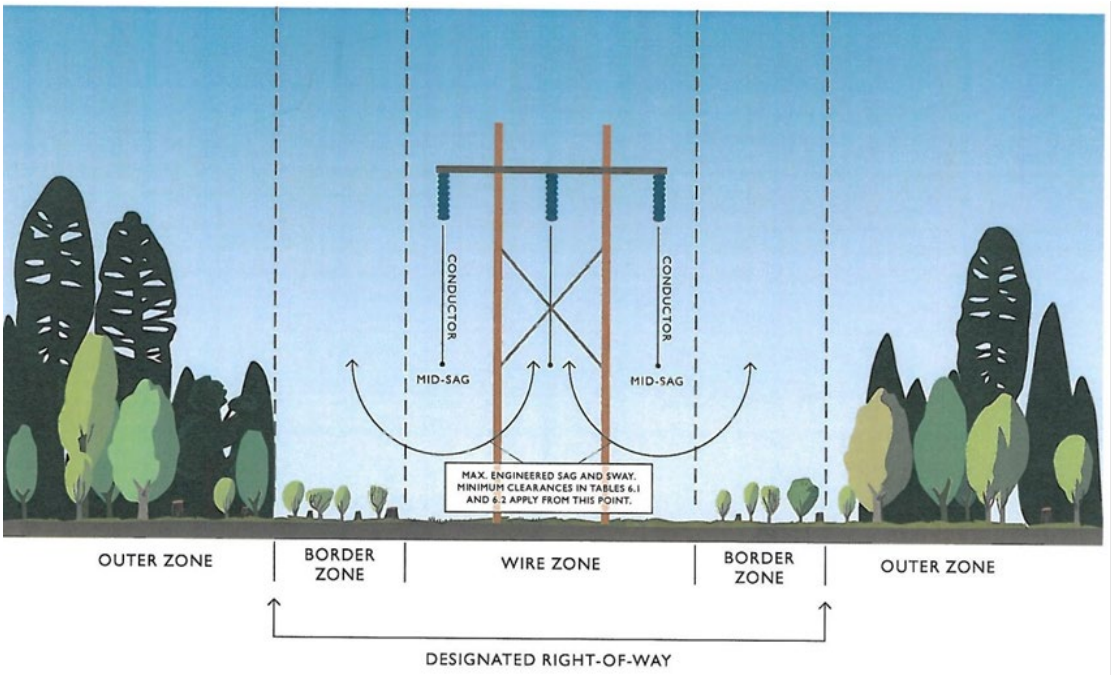

Figure 3.9. Bramble and Byrnes wire zone-border zone (adapted from Bramble et al. 1985; Yahner et al. 2004).

Sloped Terrain. On slopes and adjacent to slopes, the wire zone and border must be adjusted according to the degree of the slope(s). The wire zone is extended on the upslope, because of wire sag and sway. Consequently, the border zone on the downslope may be extended or reduced proportionately (**Figure 3.10**).

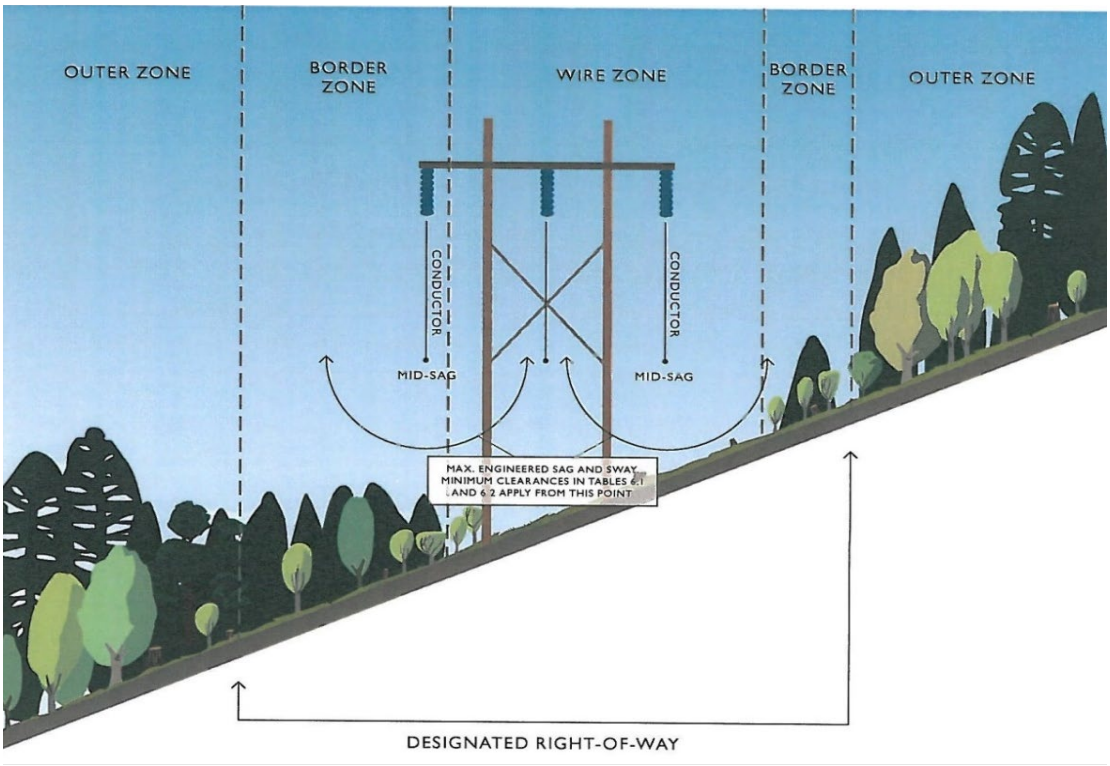

Figure 3.10. The border zone is condensed on upslopes, where wire sag and sway could bring it into contact with trees and is extended on downslopes.

Varying Terrain. When the terrain varies, the wire zone, border zone concept adapts to the changes in elevation. The type of vegetation allowed in either the wire zone or the border zone is dependent on the height of the conductors, at maximum engineered sag and sway, relative to the ground, with attention to side slope. When a transmission line crosses areas of variable elevation between structures, there are additional clearance considerations, broken into three regions. (See **Figure 3.11**.)

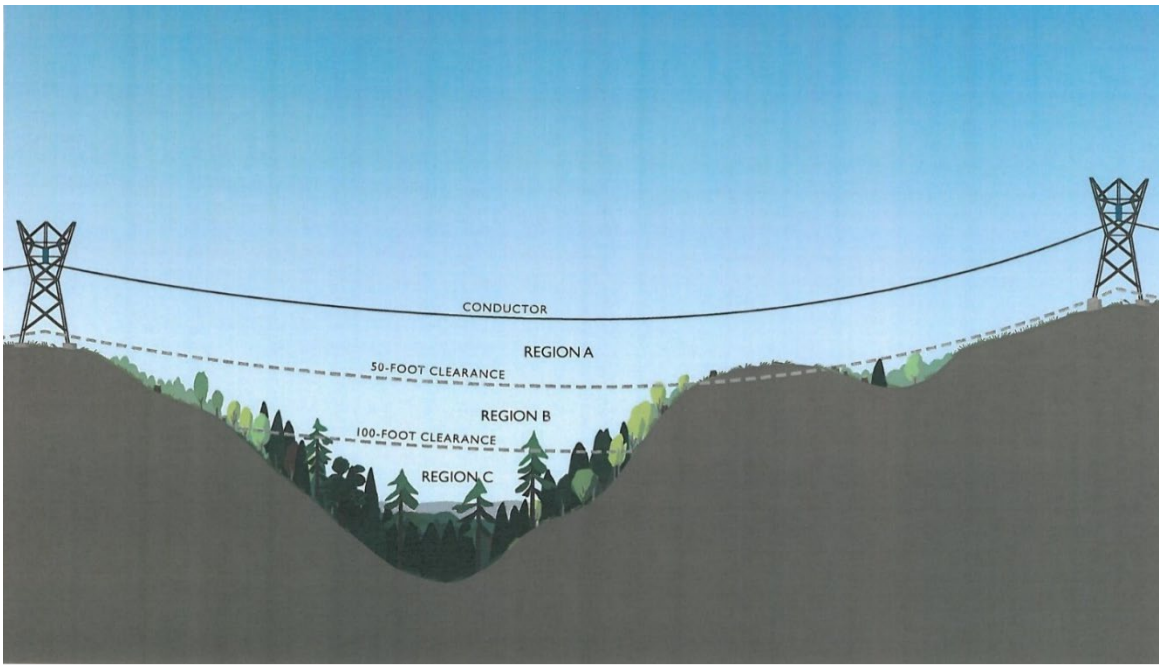

Figure 3.11. Transmission under-clearance regions.

The ROW in each of Region A, B, and C should be cleared as follows:

- Region A (Under 50 Feet). Region A is the area where lines are less than 50 feet off the ground. The 50-foot height should be from maximum engineered sag and sway. The Region A wire zone and border zone are managed no differently than flat terrain.
- Region B (50-100 Feet). Region B occurs where the lines are between 50 and 100 feet off the ground from maximum engineered sag and sway. In Region B, tall shrubs or short trees (up to 25 feet in height at maturity), grasses, and forbs may be established throughout the ROW, including the Region B wire zone. Note that many transmission structures are tall enough that conductors are over 50 feet high on and near the structures. In such cases, a border zone community may be maintained near structures, but care should be taken to maintain access to the structure as specified in Section 6.1.1.
- Region C (Over 100 Feet). Region C is where the lines are 100 feet or more off the ground. Tall-growing trees may be allowed in any zone in Region C provided they do not encroach Action Thresholds at full maturity.

4. PLANNING, SCHEDULING, AND REPORTING WORK

PacifiCorp plans and schedules vegetation maintenance depending on several factors. Typically, distribution lines are scheduled and worked systematically on a regular cycle. The specific requirements for distribution cycle maintenance is set forth in Chapter 5. Transmission overbuilds on distribution lines are worked in conjunction with distribution projects, so transmission overbuilt is also worked on a cycle, per the specifications described in Chapter 6. For all transmission lines, PacifiCorp Foresters will schedule vegetation maintenance based on an assessment of each transmission line. This is described in Section 6.3.

4.1 Basic Workflow

No work may begin on any project until a Forester has authorized such work in writing. The master contract with the Contractor specifies the manner in which work is authorized. Typically work is authorized through issuance of a "**Work Release.**" A Work Release authorizes a contractor to proceed with a specific project and provides additional written instructions for the work's completion. Contractors will not be compensated for work performed on projects not authorized through a Work Release.

The Work Release specifies the project type and may provide additional instructions on discretionary tree removals, tree replacements, use of chemical treatments, and other particulars. The Work Release sets forth required completion dates.

The Supervisor, general foreperson, or their designee, of the Contractor conducting tree work, shall post-audit the entire line/grid associated with the Work Release to ensure compliance with specifications identified within these SOPs.

After the work on a project is finished, the Contractor shall deliver to the PacifiCorp Forester a written acknowledgment that the work is complete. The Work Release document typically includes a signature block for a written acknowledgment that work is complete. In acknowledging that the work on a project is complete, the contractor guarantees that the work required under the Work Release has been completed consistent with all of the specifications set forth in these SOPs and the Work Release. Any exceptions shall be annotated in writing on the acknowledgement.

As always, safety is the highest priority. If a Forester witnesses an egregious safety violation by a contractor, the Forester may (a) require that work on a project is suspended until the safety issue is adequately resolved or (b) terminate a Work Release without any penalty to PacifiCorp.

4.1.2 Project Planning

While it is the contractor's sole responsibility to manage its workforce to complete work by the required completion date, open communication between Foresters and the Contractor management is valuable to facilitate the orderly progression of work. PacifiCorp maintains a historic database on work performed by vegetation management contractors, including information on the type of work performed, and the person-hours charged to complete these

tasks. To assist with project planning, historical information about certain locations may be provided.

A Work Release identifies the PacifiCorp Forester responsible for the project associated with the Work Release. The Forester is the Contractor's direct point of contact for all questions related to the project. In conjunction with project planning, the PacifiCorp Forester will notify internal stakeholders, as needed, including potentially operations managers, environmental support, regional business managers, line patrolmen, hydro facility site managers, regulatory affairs, and other personnel.

The Contractor performing the work is responsible for developing the project plan and deciding how work will be completed. In developing the project plan, the Contractor should factor certain issues that may be implicated in the project plan and performance of work, as follows:

- Chemical Permits. Pesticide use permits are required in certain jurisdictions, particularly on federally managed land. If a permit is required, the contractor must confirm that the permit has been acquired before herbicide application may proceed.
- City/Municipal: City and municipal arborists/foresters/managers shall be contacted to discuss activities before customer notification for vegetation maintenance.
- Concerned Customers. Customers who previously requested that the contractor (i) make personal contact before performing work, (ii) comply with special access restrictions (i.e., property owners who have requested tree crews not use a particular gate or drive) or perform work consistent with time-sensitive instructions (e.g., to refrain from work before a hay harvest).
- Dangerous Customers. Certain property owners that have exhibited opposition to work in the past. PacifiCorp cannot guarantee that every dangerous customer is identified.
- Environmentally or Culturally Sensitive Areas. Governmental, tribal, and environmentally sensitive lands present particular demands. Lands under governmental or tribal management and environmentally sensitive areas should be identified early to allow time to work through the required processes. The Contractor will identify federal, state, county, city, and pertinent non-governmental organizations potentially affected by the project. The appropriate entity shall be notified of the impending project and asked whether or not they have any concerns.
- Federal Lands. The Contractor must ensure the conditions in the pertinent special use or ROW permits are satisfied.
- Hydroelectric Facilities. PacifiCorp hydroelectric facilities and adjacent ROW could have restrictions on vegetation management activities. PacifiCorp's hydro operations and compliance personnel, PacifiCorp ROW services, or PacifiCorp environmental services shall be contacted before activities on or adjacent to hydroelectric facilities begin. Tree crews working on property that is part of a hydroelectric project site should check in with the plant office before beginning work and check out after work each day.

- Mobile Home Parks and Apartment Complexes. Mobile home park and apartment complex managers should be notified in advance of planned work. Even when managers are notified, individual units may still need notification of impending work.
- Other Permits. All required permits shall be obtained by the Contractor before work proceeds.
- Schools. School main or administrative offices should be notified of work to be done within school grounds or on property adjacent to schools and of any stipulations associated with such work.
- Ticket Work. PacifiCorp will provide the Contractor with past ticket work requests associated with a circuit or grid, representing instances that customers had called in work requests that were not an immediate threat to safety or electric service and could wait until regularly scheduled work. The contractor shall perform such work or explain to the customer the reasons why the work does not need to be completed at this time.
- In addition, other topics to consider include: traffic obstruction, line configuration, and archeological sites.

Before any field work begins on public lands, a meeting should be conducted with appropriate governmental agencies that have interest in the project, including Bureau of Land Management and the National Forest Service. And before any field work begins on tribal lands, a meeting should be conducted with appropriate tribal leaders. Multiple projects and multiple agencies may be covered by a single meeting. Meetings (either in person or remotely) will be organized by the Forester, and an appropriate representative of the Contractor management is required to participate. PacifiCorp's environmental services may attend as appropriate. Work on public and tribal lands shall not begin until written notice to proceed is received from the appropriate agency or leader. If environmentally or culturally sensitive areas are identified on public lands, the work plan should identify such areas as avoidance areas or areas with restrictions.

Tree crews should be supplied with copies of the Work Release(s) and permit(s), so that crew members are able to produce required documentation to the appropriate authorities on demand.

4.1.3 Work Identification

Vegetation requiring work is generally identified before the tree crew's arrival. In general, work is identified by a Forest Technician (Inspector or CUF) performing what is commonly referred to as a "pre-work inspection" or "vegetation-inspection." The Inspector reviews the line ahead of the tree crew and identifies the work that the tree crew will perform. Depending on the circumstances of the work, the Forest Technician is sometimes employed by the contractor performing the physical vegetation maintenance or sometimes employed by a different contractor retained specifically to perform the pre-work inspection only. In all circumstances, the Forest Technician is responsible to identify the work according to specifications provided in Chapter 5 for work on distribution lines and in Chapter 6 for work on transmission lines.

4.2 Reporting Work

All vegetation maintenance shall be documented in PacifiCorp's digital work management software, consistent with data entry instructions provided by PacifiCorp. For example, a Forest Technician documents the work to be performed during a pre-work inspection, and a crew leader documents the completed work. As indicated above, when all work is complete, the Contractor will report that all work on a project is inspected and/or complete by delivering a written acknowledgment of work completion. Contractors are responsible for furnishing suitable mobile devices to their personnel, unless indicated otherwise, to be used for data collection and running PacifiCorp's work management software.

4.3 Quality Review

A PacifiCorp Forester will occasionally, at the Forester's discretion, review the work of a particular tree crew or segment of line, before completion of all work on a project. The PacifiCorp Forester may also perform a worksite inspection. The primary purpose of these activities is to provide a quick and preliminary quality assurance assessment, including review of work documentation. Catching deficiencies and identifying the crew behaviors that produce such deficiencies early will very likely improve the quality of the tree crew's subsequent work. (The Contractor shall fix any work deficiencies identified during a tree crew review before submitting an acknowledgement that the work is complete.) A quality review does not constitute acknowledgement by PacifiCorp that work is complete. The Contractor remains responsible for fully performing the required work according to all applicable specifications. Instead, a quality review is intended to help the Contractor complete work and to foster cooperation and open communication between the PacifiCorp Forester and the Contractor.

4.5 Post-Work Audits

PacifiCorp may audit any work after it is performed. The primary purpose of an audit is quality assurance. In performing a post-work audit, PacifiCorp is not responsible for identifying any work deficiency. In performing a post-work audit, PacifiCorp does not waive or release any of its contractual rights. All contractors performing vegetation maintenance remain responsible, always, for ensuring that all work performed by the Contractor is completed to the specifications required under these SOPs and the applicable Work Release.

If a work deficiency is identified during an audit, the Contractor shall remedy the deficiency at the Contractor's sole cost. If Contractor disputes that there was a deficiency, Contractor shall still complete the requested work but may be entitled to payment on regular time and expense rates. If Contractor disputes that there was a deficiency, the Contractor and PacifiCorp will confer in good faith to determine whether the work should be performed at the Contractor's cost or subject to additional payment on regular time and expense rates.

5. DISTRIBUTION PROCEDURES

Distribution lines are overhead facilities energized at a voltage lower than transmission lines (which are typically 46 kV or greater, although there are some 34.5 kV transmission lines in certain areas). Distribution "primary" voltage typically ranges from 750 to 45,000 volts; typical distribution lines are 7,500 or 12,500 volts. Typically, lines energized below 750 volts are "secondary" lines.

5.1 Distribution Cycle Maintenance

Trees and vegetation are pruned from distribution facilities on scheduled cycles. Facilities are worked systematically, either by circuit or grid. The duration of a cycle is dependent on local conditions, as determined by PacifiCorp. PacifiCorp typically schedules distribution cycle maintenance work on a three-year cycle for most circuits in PacifiCorp's service territories. (Because of local conditions, some areas are worked on different cycles. For example, circuits in Wyoming are typically scheduled for work on a four-year cycle, while certain urban areas have a two-year cycle.) PacifiCorp dictates the work schedule by issuing Work Releases to vegetation management contractors.

In performing distribution cycle maintenance, contractors are required to:

- Systematically prune trees and other vegetation a specified distance from all primary conductors and non-primary conductors, consistent with this section
- Comply with all other specifications generally applicable to all vegetation maintenance under these SOPs, including without limitation:
    - Identify and remove (or remediate) Hazard Trees and discretionary tree removals, consistent with Section 2.4.1
    - Identify and correct readily climbable trees that are too close to power lines, consistent with Section 2.1.3
    - Identify and remedy or remove tree houses violating the criteria specified in Section 2.1.4
- Remove all brush, which includes volunteer trees (naturally seeded, non-landscaped trees) and woody plants (including vines), that are less than 6-inches in diameter at breast height

  The actual square footage occupied by the aboveground portion of the plant should be measured and recorded, with a 100 ft^2 maximum per plant for both pruned or removed vegetation. Note that multi-stemmed woody plants where no single stem is over 6-inches in diameter are classified as brush, with a maximum of 100 square feet per plant.

- Apply herbicide to all volunteer trees and to the stump(s) of subject trees that were identified for removal (presuming the property owner has not expressed objection to herbicide application)

- Comply with any other work requirements specified in a Work Release for a particular project

5.1.1 Distribution Cycle Maintenance – Clearance Distances – Primary

Each work cycle, trees and other vegetation are pruned or removed to achieve clearance distances to comply with the NESC, state regulation clearances requirements, and PacifiCorp guidelines. (Because of the application of natural target pruning techniques described in Section 3.2.1, the actual distances achieved after work is performed may exceed the Post-Work Clearance distances specified.) Specified vegetation clearance distances from primary conductors in the distribution system should allow sufficient space to prevent contact with primary conductors or regulatory mandated clearance distances throughout the cycle.

The Contractor is responsible to identify all vegetation that would encroach upon conductors, PacifiCorp required distances, or regulatory mandated minimum clearance distances throughout the cycle.

A "**Post-Work Clearance**" dictates the minimum clearance distance that must be accomplished at the time that the work is performed. The Contractor is required to achieve post-work clearance distances. As a result, the contractor may need to exceed the post-work clearance distance on subject trees to meet ANSI A300 pruning standards.

Unless otherwise specified in a particular Work Release, the Post-Work Clearance distances are set forth as follows in **Table 5.1**:

Table 5.1. Distribution primary – (minimum) Post-Work Clearance distance chart**.**

	Slow-Growing	Moderate-Growing	Fast-Growing
Side Clearance	8 feet	12 feet	14 feet
Under Clearance	10 feet	14 feet	16 feet
Overhang Clearance	12 feet	14 feet	14 feet

Neutral conductors in a raised position, which includes above or on a crossarm, are treated as primary conductors for purposes of this section. Neutral conductors in a low position are treated as non-primary, addressed below.

5.1.1.1 Minimum Extended Post-Work Clearances

In some circumstances, typically in areas of elevated wildfire risk, minimum extended Post-Work Clearances are required.

In California, minimum extended Post-Work Clearances distances are to be achieved for all distribution maintenance whether located within or without an area of elevated wildfire risk.

Minimum extended Post-Work Clearance distances are set forth as follows in

Table 5.2. Distribution primary – (minimum) extended Post-Work Clearance distance chart.

	Slow-Growing	Moderate-Growing	Fast-Growing
Side Clearance	12 feet	12 feet	14 feet
Under Clearance	12 feet	14 feet	16 feet
Overhang Clearance	12 feet	14 feet	14 feet

5.1.3 Distribution Cycle Maintenance – Clearance Distances – Non-Primary

A secondary line is a line typically energized to less than 750 volts. Specified distances from secondary conductors in the distribution system are designed to prevent strain (severe deflection) or abrasion. The "**Work Threshold**," which is the point at which action must be taken) and Post-Work Clearance distances for non-primary are set forth as follows:

Table 5.3 Non-primary wire vegetation clearance distances.

Line Type	Work Threshold	Minimum Post-Work Clearance
Non-insulated wire pole-to-pole secondary	N/A	3 feet
Neutral low position	Contact	2 feet
Insulated pole-to-pole secondary	Deflection or abrasion	2 feet
Non-insulated secondary service line/streetlight	N/A	1 feet
Insulated secondary service/streetlight	Deflection or abrasion	1 feet
Guy wire	2-inch or greater diameter limb applying pressure	Relieve pressure

In addition to the specification clearances (**Table 5.3**), the following requirements also apply to distribution cycle maintenance work on distribution non-primary.

- Tree Limbs Between Conductors: Any tree limbs between a primary conductor and any secondary conductor, regardless of type, shall be removed or pruned to Post-Work Clearances for primary.
- Customer Work: If a customer expresses a desire to remove other limbs or trees around any non-primary, in addition to the work to complete under these specifications, vegetation maintenance workers should inform the customer to call the customer service line to arrange for a temporary disconnection of the facilities to allow safe completion of the desired tree work, as required by law.

5.1.4 Distribution Cycle Maintenance – Other Facility Clearances

In addition to pruning trees to maintain clearances, certain vegetation maintenance is required on utility poles (and supporting guy wires) as part of distribution cycle maintenance work. One-third of the circumference around poles shall be cleared of vegetation to a distance of 5 feet from the pole to allow linemen a climbing path. The remaining two-thirds of the pole circumference should be cleared of all vegetation 1 foot from the pole.

Vines growing on poles and guy wires shall be:

- Cut at ground level
- Treated with an approved herbicide
- Removed from the bottom 5 feet of the pole or guy wire
- Reported as brush (< 6-in. DBH) or tree (> 6-in. DBH) removed

Vines clearly part of a landscape and rooted well away from the pole may be:

- Pruned to provide sufficient climbing path and 5 feet of separation (e.g., 5 feet of separation between the top of a fence and facility)
- Reported as brush pruned (not to exceed 100 brush ft. pruned)

Where vines remain on facilities after work is completed in accordance with Section 4.2, the Contractor will document the exception and report it to operations to clear the remainder of the pole.

5.2 Off-Cycle Inspections and Maintenance

In certain locations, PacifiCorp may schedule an Off-Cycle Inspection for circuits, typically, in years when the circuit is not scheduled for distribution cycle work. Off-Cycle Inspections are typically scheduled in areas of elevated wildfire risk. Off-Cycle Inspections are primarily designed to identify Hazard Trees. Off-Cycle Inspections are also used to identify vegetation that will likely exceed minimum clearance requirements, as established by state law, regulation, and the National Electric Safety Code (NESC) before the next scheduled work.

In performing Off-Cycle Inspection and Maintenance, the Contractors is required to:

- Prune trees and other vegetation, identified during an Off-Cycle Inspection, to the Post-Work Clearance distances set forth in Sections 5.1.1 and 5.1.2
- Identify and remove Hazard Trees, consistent with Section 2.4.1
- Any other work requirements specified in a work release for a particular project

5.3 Distribution Ticket Maintenance

Customers, district operations staff, governmental bodies, regulatory agencies, or others alert vegetation management to real or perceived conflicts between trees and power lines. The intent of ticket maintenance is to correct imminent and unreasonable safety or electrical service risks. Upon notice of a potential vegetation condition, a contractor is assigned to assess the issue. If a vegetation condition is discernable as an emergency, it should be corrected promptly. If a condition poses an immediate risk to electric service, the condition should be corrected within a reasonable period.

Conditions that present an immediate risk to electrical service may include:

- Trees that have caused an outage
- Trees violating specific state regulatory regulations

- Limbs that are deflecting secondary conductors to the extent they present a high probability of damaging hardware before the next scheduled cycle work
- Readily climbable trees
- Trees near tree houses
- Hazard Trees as described in Section 2.4.1
- Trees where the property owner requires clearance so non-utility line clearance workers may work the tree (this complies with various state line safety laws and may be billed to the requesting party)

If the condition does not pose an immediate threat to electric service, work is not required. In all circumstances, the party concerned shall be contacted regarding the inspection determination. Personal contact is preferred.

5.4 Major Woody Stem Exemption

Side clearances from conductors may be reduced to 20 inches for structurally sound limbs or tree trunks greater than 8 inches in diameter at wire height, provided the tree is not readily climbable. Increased side clearance to 36 inches is encouraged with Forester approval.

In the state of California, Major Woody Stem Exemptions must meet or exceed the exempt minimum clearance provisions set forth in California Code of Regulations Title 14, Section 1257 requirements.

All Major Woody Stem Exemptions associated with construction projects require Forester approval.

5.5 Pole Clearing

PacifiCorp performs pole clearing in certain areas, usually to mitigate wildfire risk beyond clearing activities described in Section 5.1.4. Pole clearing as described in Section 5.5, is generally not required under normal distribution cycle maintenance. Instead, if a work release specifies Pole clearing be accomplished on specific poles identified in the work release, this section will apply. PacifiCorp typically selects certain poles for pole-clearing activities because of equipment on the structure that may emit a spark. Pole clearing primarily involves the removal of herbaceous and volunteer woody vegetation to bare ground in a 10-foot radius (up to 8 feet vertically) of clear space around subject poles. To increase the long-term effectiveness of pole clearing, herbicide and/or soil sterilant will be applied to prevent regrowth (unless prohibited by law or the property owner). This cleared space should be established and maintained by removing flammable, trash, debris, or other materials, grass, herbaceous brush, and pruning or removing aboveground branches and plant parts. Pole clearing in California shall be completed consistent with California Public Resource Code Section 4292 at all times.

5.6 Pad-Mounted Transformers

Pad-mounted transformers should not be cleared as part of normal distribution cycle maintenance. This maintenance is performed by the PacifiCorp's operations department. Qualified line clearance tree workers are not required to clear pad-mounted transformers but may

be assigned to remove shrubs and other low-growing vegetation around pad-mounted transformers.

6. TRANSMISSION PROCEDURES

Transmission facilities are overhead lines energized at a higher voltage. While there are some 34.5 kV transmission lines, typical transmission voltages on PacifiCorp's system are 46, 69, 115, 138, 161, 230, 345, and 500 kV. Facility voltage and type determine the amount of transmission clearance needed.

Vegetation maintenance performed on transmission lines shall comply with ANSI A300. In addition, vegetation maintenance performed on transmission lines shall conform with the NERC Reliability Standard FAC-003-5. Consistent with requirement R4 of NERC Standard FAC-003-5 and the procedures set forth in PacifiCorp transmission grid operations Procedure PCC-215, PacifiCorp line patrolmen are responsible to complete inspections on certain transmission lines. When doing their inspections, line patrolmen will identify any vegetation that poses a threat of causing a transmission outage. In addition, PacifiCorp's vegetation management department completes vegetation inspections of the ROW for transmission lines. PacifiCorp's vegetation management completes an annual vegetation inspection on main grid transmission lines.[1] All other transmission lines are inspected at least once every three years. Vegetation maintenance on transmission lines is then scheduled according to the results of those inspections.

To maintain required clearances between vegetation and transmission lines, PacifiCorp uses standard clearance activities, as described in Section 6.1 below. In addition, PacifiCorp's vegetation management philosophy for transmission lines is to incorporate the IVM best practices described in Section 3.4 whenever and wherever reasonably feasible, including those strategies to cultivate stable, low-growing plant communities comprised of plants that will never interfere with transmission lines in their lifetime. As the most efficient long-term strategy, vegetation maintenance incorporating IVM principles is encouraged as much as feasible and subject to property rights. Incompatible tree species are removed in an established ROW wherever and whenever allowed. In addition, PacifiCorp Foresters and Contractors may consult on the potential application of IVM principles in reference to specific projects.

6.1 Transmission Clearances

The objective of systematic transmission work is to safeguard the reliability of PacifiCorp's transmission system by preventing outages from contact with vegetation. Clearance work on a transmission line is guided by three concepts: Minimum Vegetation Clearance Distances, Action Thresholds, and Minimum Clearances Following Work.

Minimum Vegetation Clearance Distance (MVCD) represent radial distances from the conductors inside of which trees shall not encroach. These distances are established in FAC-003-5 and must be maintained.

[1] Main grid transmission lines are all lines operating at voltages exceeding 200 kV and transmission lines operated below 200 kV identified by the planning coordinator or transmission planner as a facility that if lost or degraded is expected to result in instances of instability, cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System (BES) for a planning event or is identified as an element of a major Western Coordinating Council transfer path in the BES.

Action Thresholds are designed to provide a 10-foot buffer from the MVCD. Clearance work is performed if vegetation is identified within the Action Threshold distance from a conductor.

Minimum Clearances Following Work are designed to always maintain an appreciable buffer with the MVCD. If a tree is within the Action Threshold and pruned, it should be cleared to the Minimum Clearance Following Work.

The MVCD for specific voltages is set forth in **Table 6.1**. Because of the buffers built into the Actions Thresholds and the Minimum Clearances Following Work, a violation of MVCD should very rarely occur, usually only because of a dramatic change in the vegetation, such as a tree that has partially fallen. If vegetation is ever identified within the MVCD, the vegetation shall be corrected within 24 hours, consistent with PacifiCorp transmission grid operations operating procedure PCC-215.

Consequently, routine vegetation work on transmission lines is typically completed with reference to the Action Threshold and Minimum Clearances Following Work. If a Work Release is issued regarding any transmission line, or any segment of a transmission line, the contractor shall perform vegetation maintenance on any vegetation within the Action Threshold applicable to the line. In performing work, the Contractor shall prune or remove vegetation so that Minimum Clearances Following Work is achieved with respect to the vegetation being worked. The applicable Action Threshold and Minimum Clearances Following Work are determined by reference to the following table:

Table 6.1. Transmission clearance requirements (in feet).

	Line Voltage							
	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	69 kV	> 69 kV
MVCD	8.5′	5.3′	5.0′	3.4′	2.9′	2.4′	1.4′	N/A
Action Thresholds	18.5′	15.5′	15.0′	13.5′	13.0′	12.5′	10.5′	10.0′
Minimum Clearances Following Work	50.0′	40.0′	30.0′	30.0′	30.0′	30.0′	25.0′	20.0′

The MVCD represents minimum clearances that should be always maintained from conductors, considering the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. MVCDs in **Table 6.1** are for 10,000-11,000 feet (about 3.35 km) above sea level (Table 2 of FAC-003-5) and apply across PacifiCorp's service territory regardless of elevation.

6.1.1 Clearances for Structures and Guy Anchors

Vegetation should be cleared within a 25-foot radius of transmission "H" or metal structures, a 10-foot radius of single-pole construction and a 5-foot radius of guy anchors. Clearing activities shall not damage poles, structures, guys, or anchors. Grasses, forbs, ferns, and other herbaceous species may be left around structures and guys at the PacifiCorp Foresters discretion.

6.1.2 Guy Wires

Trees or branches 2 inches or more in diameter applying direct pressure to or threatening to fall on or through poles or guy wires shall be removed or pruned.

6.1.3 Removals in Transmission Rights-of-Way

Hazard Trees. All Hazard Trees shall be identified and removed.

Discretionary Removals. In addition, when performing vegetation maintenance on transmission ROW, removal of vegetation is superior to pruning. Within the ROW, vegetation should be removed consistent with IVM principles where feasible. In general, wire zone and border zone concepts should be applied consistent with IVM principles. (See **Table 6.2**.)

Table 6.2. Typical transmission ROW widths.

Facility	Distance From Center (ft.)	Urban Width (ft.)	Rural Width (ft.)
46 kV Single Pole	25.0	50.0	50.0
69 kV Single Pole	25.0	50.0	50.0
115 kV Single Pole	30.0	60.0	60.0
138 kV Single Pole	30.0	60.0	60.0
161 kV Single Pole	40.0	80.0	80.0
230 kV Single Pole	40.0	80.0	80.0
69 H-Frame	40.0/50.0	80.0	100.0
115 H-Frame	40.0/50.0	80.0	100.0
138 H-Frame	40.0/50.0	80.0	100.0
161 H-Frame	40/50	80.0	100.0
230 H-Frame	62.5	125.0	125.0
345 H-Frame	75.0	150.0	150.0
345 Steel Tower	75.0	150.0	150.0
500 Steel Tower	87.5	175.0	175.0

In some circumstances, where individual property rights affecting the width of the ROW are contested, Foresters may consult with PacifiCorp ROW services to determine the width of a ROW.

6.2 Emergency Tree Action Form

As noted above, line patrolmen complete inspections consistent with FAC-003-5 and PCC-215. line patrolmen encountering a tree that poses a threat of causing a transmission outage at any moment will (i) immediately notify the grid operator by phone and describe the nature and extent of the threat; (ii) complete and process the Emergency Tree Action Form. To process the Emergency Tree Action Form, the line patrolman will save an electronic copy of the form to the FAC-003-5 shared drive for compliance tracking and communicate the vegetation conditions to vegetation management for urgent attention. The line patrolman's communication should include the applicable Emergency Tree Action Form.

6.3 Transmission Work Planning

PacifiCorp's vegetation management annually reviews inspection results and schedules vegetation maintenance accordingly. As indicated above, inspections of main grid transmission

lines occur annually, and inspections for all other transmission lines, typically referred to as "local transmission," occur at least once every three years. Such inspections may be staggered, so long as at least one inspection occurs at least once every three years. Where there is distribution underbuild, the transmission line on those structures shall be inspected concurrently with the distribution line on its regular cycle. Transmission line inspections are generally end-to-end – the entire line from one substation to other substation, which defines the transmission line segment scheduled for inspection.

When conducting an inspection of transmission facilities, the inspector shall, at a minimum, identify vegetation for work as follows:

- Any conditions that may violate MVCD and pose an imminent threat of a transmission outage shall be reported to the PacifiCorp Forester for immediate resolution
- Any conditions that are likely to pass the Action Threshold during the following growing season shall be identified for work in the following calendar year
- Any conditions that are likely to pass the Action Threshold within two years shall be identified for work in the second calendar year following the inspection

In all cases above, the Inspector shall identify vegetation consistent with IVM principles, where feasible, as identified within these SOPs to achieve PacifiCorp's desired outcomes.

Transmission maintenance is based on inspection results and should consider line voltage, line importance, vegetation conditions that violate the Action Thresholds in **Table 6.1**, location, predominant species' growth rates, threatened and endangered species, archeological sites, topography, and other factors. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work is sufficient at all locations on the ROW.

6.4 Mitigation Measures

FAC-003-5, requirement R5 directs transmission owners to develop mitigation measures to achieve sufficient clearances for protection of the transmission facilities when it identifies locations on the ROW where the transmission owner is restricted from performing work that may lead to a vegetation encroachment into the MVCD. Before implementing the next annual work plan, the owner shall take corrective action to ensure continued vegetation management to prevent encroachments.

Whenever the restriction is caused by a landowner, the refusal process in Chapter 8 shall be followed. If the refusal process has been completed without attaining clearances that would prevent encroachment into the MVCD before the next scheduled work, such locations must be documented on the Work Release. These sites should be reported in writing to the appropriate line patrolman within 30 days. The line patrolman should report annually on these site's status.- In addition, Foresters shall arrange to have the site inspected at least biannually.

6.5 Vegetation Screens

Vegetation screens may be required by federal or local authorities at high-visibility areas like major road crossings. Where these mandates exist, vegetation screens should consist of border zone communities and be located near structures (where the line is unlikely to sag), if possible. If no border zone species are present, tall-growing trees may be left provided they have at least the minimum clearance following work in **Table 6.1** following scheduled work.

Leaving tall-growing trees in transmission ROW should be discouraged because they impede cover type conversion. Vegetation screens should be no more than 25 feet from frequented vantage points into the ROW.

6.6 Merchantable Timber

The ROW could contain merchantable timber. "**Merchantable timber**" is defined as trees with at least six-inch diameter at breast height (DBH) that are recoverable and have a market in the local area. Merchantable timber belongs to the property owner unless the easement or permit states otherwise. If merchantable timber needs to be felled, the property owner should be contacted regarding timber recovery. After the merchantable timber is felled, it should be de-limbed and left in total tree length on the ROW for recovery by the owner.

6.7 Transmission Communication Procedures

6.7.1 Pre-Work Communication with Control Center

Operative communication capability is always mandatory on transmission ROW communication with the control center is critical for tree crew safety. Before starting transmission maintenance, tree crews shall contact the control center from the ROW and provide the following information to comply with system operations Policy 152:

- Name of crew leader
- Name of company
- Contact information (radio or cell number)
- Name of transmission line
- Line section (substation names between which work is to occur, such as "Alvey to Dixonville," or "Ben Lomond to Terminal")
- Location of work (structure number, address, or both)
- How long the crew will be working at that location
- Radio or cell phone number of the crew
- Name of the supervisor for the tree crew and the supervisor's cell phone number

If verbal contact cannot be made with the control center from the ROW, non-emergency work shall not be performed at that site. The crew should relocate to work where they can communicate with the control center. Satellite phones or similar devices might be necessary in remote locations to provide the required communication and are the responsibility of the Contractor.

6.7.2 Post-Work Communication with the Control Center

After completing transmission work for the day, tree crews shall call the control center and provide the following information:

- Name of crew foreman
- Name of company
- Contact information (radio or cell number)
- Name of transmission line
- Line section (substation names between which work occurred, such as “Alvey to Dixonville,” or “Ben Lomond to Terminal”)
- Location where work was performed
- Notice that crew members and equipment are off the ROW or in the clear.

7. CHEMICAL PROCEDURES

Herbicides and tree growth regulators (TGR) are an important part of PacifiCorp's Vegetation Management Program. Herbicides are chemicals used to manipulate or control undesirable vegetation. When safely used, herbicides are effective and efficient, minimize soil disturbance, and enhance plant and wildlife diversity. Herbicide application can benefit wildlife by improving forage as well as escape and nesting cover. In some instances, noxious weed control is a desirable objective on utility ROW that can be accomplished through herbicide treatment. Herbicide use can control individual plants that are prone to resprout or sucker after removal. When trees that resprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat (Yahner and Hutnik 2004). Treating suckering plants allows early successional, compatible species to dominate the ROW and out-compete incompatible species, reducing work. "**Tree growth regulators**" refers to chemical treatments that slow the growth of some tree species.

Chemical applications shall always be performed according to federal, state, and local regulations and consistent with all labeling requirements. In addition, the provisions of this Chapter 7 shall apply to all chemical applications.

7.1 Notification to Property Owners

Before chemical use on a property, contractor shall give notice to the property owner(s). Notice shall be provided at least five days before work but no more than six weeks in advance, whenever chemicals are to be used on their property. If a property owner objects to chemical use, the contractor shall not apply chemicals on that property.

7.2 Licensed Applicators

Supervisors in all states across the PacifiCorp service territory shall hold a valid Commercial Pesticide Applicator License. In all states across the PacifiCorp service territory, except for California, crew leaders and qualified tree trimmers (with more than one year on the job) shall hold a valid Commercial Pesticide Applicator License.

The Contractor performing work is always responsible to ensure that any application of chemical is performed by an applicator with a valid applicator's license or under the supervision of a certified applicator, as required by state law where the property is located.

7.3 Closed Chain of Custody

The contractor making the application is responsible for chemical purchase, storage, and container disposal. Closed chain of custody is required including the use of returnable, reusable supply containers. For cut stump and basal application a handheld sprayer is to be filled at the start of each working day, for each tree crew (Goodfellow et al. 2011).

7.4 Chemical Reporting

All chemical applications shall be documented as required by law for a licensed applicator. In addition, chemical applications shall be documented as instructed by PacifiCorp, consistent with Section 4.2. The contractor making the application shall be responsible for maintaining reports and shall produce reports for review by the state departments of agriculture upon request.

7.5 Herbicide Application Efficiency

Ninety-five percent control shall be assumed on all herbicide applications to be considered effective. Treatments exhibiting less than 95% control may need to be retreated at the contractor's expense.

7.5.2 Wetlands and Waterbodies

Product label shall be followed and approved for use near wetlands and waterbodies.

7.5.3 Spills

Contractor is responsible to prevent any chemical spills from occurring. Special attention should be made while mixing, loading, and cleaning equipment, which are activities that carry more risk for accidents or spills. Spills can be avoided by using closed chain of custody best management practices. Spill kits are required on every truck when any herbicide is used or being transported.

In the event of a spill:

- Stop, contain, and isolate the spill
- Report the spill to the PacifiCorp Forester, who will notify PacifiCorp environmental services; the following information must be provided to PacifiCorp Forester:
    - Caller and manager's name
    - Date and time spill
    - Location (address or longitude and latitude)
    - EPA number (product spilled)
    - Cause of spill
    - Amount of spill
    - Types of surfaces contaminated
    - Containment and/or clean-up activities performed so far
- Remediate the spill

Cleanup at or near PacifiCorp generating sites or substations must comply with site-specific spill prevention and remediation plans.

7.6 Approved Herbicides

In all circumstances, the licensed applicator is responsible to follow label requirements. In addition, specific chemical products must be approved by the responsible PacifiCorp Foresters, based on pre-approved chemical products (additions to which must be authorized by PacifiCorp's director of vegetation management). Any approved chemical products must be based on one of or a combination of the following active ingredients:

- Stump Application
  - 2, 4-D
  - Glyphosate
  - Picloram
  - Triclopyr
- Low Volume Basal Application
  - Imazapyr
  - Triclopyr
- Foliar Application
  - 2, 4-D
  - Aminopyralid
  - Fosamine ammonium
  - Glyphosate
  - Imazapyr
  - Metasulfuron methyl
  - Picloram
  - Sulfometuron methyl
  - Triclopyr
- Soil Application
  - Diuron
  - Indaziflam
  - Imazapyr
  - Picloram
  - Sulfentrazone
  - Tebuthiuron
- Tree Growth Regulators (TGR)
  - Fluprimidol
  - Paclobutrazol

8. CUSTOMER RELATIONS

Representatives of vegetation management interact with a significant number of customers. As a result, customers often develop an impression of PacifiCorp based on their experience with vegetation management. Particularly because vegetation maintenance is often controversial, excellent customer service is imperative for a successful program. Contractor personnel are required to be professional, prompt, fair and courteous to the residents, tenants, and property owners they interact with while performing work for PacifiCorp. Contractor personnel are expected to use good judgment with respect to clothing attire. Generally, that means avoiding offensive or revealing clothing. Clothing should be clean and in good repair.

Contractors are responsible for managing communications with property owners in a manner consistent with this, see Chapter 8. Communications with customers should accurately describe the work to be performed.

8.1 Educational Information

PacifiCorp has a variety of educational materials about tree-power line conflicts and planting the right tree in the right place.

The *Trees and power lines* brochure explains the need for line clearance work, as well as natural target pruning. (This brochure is used as a companion to the "yellow door card" described in Section 8.2.1 below.)

The *Small trees for small places* is a publication in PDF format available at www.PacificPower.net or www.RockyMountainPower.net. It provides tree selection tree planting and electrical safety information. It offers an easy-to-use chart on ornamental and adaptive characteristics of 100 different species that can be used adjacent to power lines. Not all these trees can be used everywhere in PacifiCorp's service territory. By providing a choice of 100 small-statured trees, however, there are several options appropriate for use in any given location around PacifiCorp's system.

The *Right tree in the right place* poster provides illustrations and descriptions of small trees that are suitable across PacifiCorp's service territory. It also provides information about proper utility tree pruning and tree planting.

8.2 Notification for Tree Work

Before vegetation maintenance, contractors shall deliver notice of planned work to the landowner or an occupant of the property (as reasonably identified). As set forth in Section 4.1.2, school administrators should be notified of work to be done within school grounds or on property adjacent to schools. Likewise, in cases of municipal, county, state, or federal properties, the proper agency representative shall be notified by the Forester or the contractor. The appropriate PacifiCorp regional business manager should be notified by the PacifiCorp Forester before meeting with governmental officials.

Notification should be given at least five business days, but no more than six weeks, before the crew arriving. Notification may be provided by mail including email, doorhanger, phone, or

personal contact. If a door hanger is used, it shall be placed at the entry way of a dwelling or business structure but shall not be placed in U.S. mailboxes. A PacifiCorp Forester may direct additional notice be given; for example, work on historic, unique, or unusual trees may warrant additional personal contact with the customer. In the circumstances of emergency response, the PacifiCorp Forester may waive notice requirements.

8.2.1 Personal Notification on Arrival

When crews arrive for work at a residential site, a member of the crew should make a courtesy knock on the door to let the homeowner or tenant know that work is about to begin. So long as the homeowner or tenant does not protest or otherwise indicate that the owner refuses to allow work, the crew may proceed with the planned work. If no one is home, the crew may proceed with the planned work. On business property sites, a door knock is not required, so long as prior notification was given.

8.3 Affirmative Customer Consent

As a courtesy and to avoid unnecessary disputes, the Contractor shall make reasonable attempts to obtain affirmative consent from a property owner prior to completing removal of mature (greater than 6 inches DBH) or any landscaped trees.

8.4 Property Owner Refusal Procedure

If a property owner refuses to allow work, the crew should not proceed with work, except as expressly allowed under the process described in this section. Detailed records should be kept of every conversation, including the date and time it occurred, and summary of the matters discussed. The Contractor must make contact (encouraged to meet with customer on site) and make at least two attempts to resolve refusal, and at least one attempt by a management level representative of the Contractor, to obtain consent before notifying the PacifiCorp Forester. If consent is not obtained, the Contractor should confer with PacifiCorp ROW services, as appropriate, to confirm PacifiCorp's right to perform the work and shall notify the PacifiCorp Forester of the refusal. The PacifiCorp Forester may instruct the Contractor management to make a final attempt to obtain consent or may attempt to obtain consent directly from the landowner. If the Forester is unable to obtain consent, the Forester shall determine whether to (i) instruct the Contractor to proceed with the work without affirmative consent or (ii) excuse the Contractor from completing the work.

8.5 Work Completed Without Property Owner Consent

If PacifiCorp holds property interests entitling it to maintain its facilities, work may proceed over a property owner's unfounded refusal. If the Forester decides to proceed with work, the Forester shall deliver to the property owner a written notice that work will proceed. The notice shall specify the date on which vegetation maintenance will be completed and describe the work. The Contractor will complete the work on the date specified in the notice.

The Forester shall alert the director of vegetation management, as well as the appropriate operations manager, regional business manager, wires director, and regulatory analyst about any

work scheduled for completion after a property owner refusal. The regulatory analyst will inform the proper regulatory agency about the action. If it appears the media could become involved, the media hotline should be notified (503-813-6018 for Pacific Power, 801-220-5018 for Rocky Mountain Power). The Forester shall take before and after photos of the site. The scheduled work should be completed, regardless of any additional objection from the property owner, unless the property owner threatens the safety of the crew or bystanders. As always, safety is the highest priority. The Forester may contact corporate security and local law enforcement to request a presence on the property while work is performed.

9. ACRONYMS

ANSI	American National Standards Institute
APM	Accident Prevention Manual
BES	Bulk Electric System
CUF	Consulting Utility Forester
DBH	Diameter at breast height
EPA	Environmental Protection Agency
ISA	International Society of Arboriculture
IVM	Integrated vegetation management
KV	Kilovolt
MBTA	Migratory Bird Treaty Act
MVCD	Minimum vegetation clearance distance
NERC	North American Electric Reliability Corporation
ROW	Right(s)-of-way
SOP	Standard operating procedures
TGR	Tree growth regulator

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Transmission Grid Operations
Operating Procedure PCC-215
Guidelines for Communication of Vegetation Conditions that Present an Imminent Threat of Transmission Line Outage

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1. VERSION HISTORY

This procedure shall be, at a minimum, reviewed annually and updated as needed.

Prior history available in PolicyTech

Date:	Action:	By:	Change Tracking:
11/22/24	Review	WM	Updated references to WECCnet to RRCMA.
08/08/22	Annual Review	MBR	Reviewed and no changes required at this time
10/7/21	Annual Review	KM	No Changes
03/11/2020	Updated	KM	Fixed formatting issues – no major changes
04/30/2019	Updated	KM	Updated formatting, removed Peak and Hiplink references
02/21/2018	Reviewed	JG	Annual review, no updates required
11/30/2016	Reviewed	JG	Annual review, no updates required
05/17/2015	Reviewed	JG	Annual review, no updates required
06/25/2014	Reviewed	JG	Revised Section 2 background

2. PURPOSE

The purpose of this operating procedure is to provide guidelines for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage so that appropriate mitigation actions may be taken until the threat is relieved.

3. BACKGROUND

The North American Electric Reliability Corporation (NERC) reliability standard FAC-003-4 "Transmission Vegetation Management" was designed to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading. PacifiCorp's Facility Point Inspection (FPI) adequately meets all provisions of this NERC standard, except for Section R4., which stipulates that:

Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

The FPI form documents and reports vegetation conditions that present a threat to transmission lines. However, the FPI process does not adequately address the need for immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. There are no documented provisions for immediately notifying the Vegetation Management, or for temporarily reducing line rating, and switching lines out of service until the threat is relieved.

This operating procedure has been developed to ensure that PacifiCorp's established communication process fully complies with the Section R4. provisions stipulated above, and that documented procedures are in place to implement temporary reductions in line rating, switching line out of service, etc., as the NERC standard requires.

4. PROCEDURE

4.1. Inspection and Communication

If, during facility point inspections, the Inspector observes vegetation conditions that present an imminent threat of a transmission line outage, he/she shall:

a) Immediately notify the Grid Operator by phone and describe the nature and extent of the threat.

Complete and process the Emergency Tree Action Form (see Section 6).

b) Save an electronic copy of the form to the FAC-003-3 shared drive for compliance tracking purposes.

Communicate the vegetation condition to Vegetation Management for urgent attention and include the applicable Emergency Tree Action Form (see Section 6)

4.2. Grid Operator Actions

When the Grid Operator receives information regarding imminent threat of a transmission line outage, as stipulated in section 4.1.(a) above, he/she shall take the following action(s):

a) Determine what action(s) to take in order to mitigate the threat, e.g.,

i. Make a determination of whether there is need to switch line out of service until the threat is relieved. ii. Make a determination of whether there is need to temporarily reduce line rating until the threat is relieved. iii. Other mitigation measures.

iv. Notify the Shift Supervisor.

b) If in section 4.2.(a) above the Grid Operator determines that the line should be taken out of service, until the threat is relieved, he/she shall, within 30-minutes[1],

i. Adjust the system and open both ends of the effected line section.

ii. The Grid Operator shall request that the situation be rectified immediately, as the system is at risk of another line outage.

iii. Notify Shift Supervisor. iv. Notify Reliability Coordinator.

v. Post any reduced limits for scheduled paths on OASIS

vi. Post a message via Regional Reliability Coordinator Messaging Application (RRCMA).

vii. Update Operator Log.

[1] That is, within 30-minutes of reaching the determination.

c) If in section 4.2.(a) above the Grid Operator determines that the line rating should be temporarily reduced, until the threat is relieved, he/she shall, within 30-minutes,

i. Adjust the system and reduce the line rating to 80% of the continuous summer rating. This becomes the temporary line rating until the threat is relieved. Schedules and actual flow on the line shall not exceed the temporary limit.

ii. If step (i) above does not result in a desired outcome, then, limit the line rating to 80% of the prevailing actual flow at the time the notification was made.

iii. The limit will be adjusted further, if Engineering Department determines a need for further restrictions.

iv. Notify the Shift Supervisor.

v. Notify Reliability Coordinator of any imminent threat and steps being taken to relieve the threat.

vi. Post any reduced limits for scheduled paths on OASIS.

v. Post a message via RRCMA.

vii. Update operator log

5. RELATED DISPLAY INFORMATION

Not applicable.

6. ADDITIONAL INFORMATION

Below is a copy of the Emergency Tree Action Form:

Date	Patrolman	Immediate Tree Work Required (no longer than 24 Hours)				Action Until Tree Work is Complete?		
		Line	Structure	GPS Location or Address	Description	Temporary reduction in line rating required?	Temporarily Switching Line Out of Service Required?	Other Action?
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
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						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	
						☐ yes ☐ No	☐ yes ☐ No	

7. NERC EVIDENCE

This document is used as evidence for the following NERC standard requirements

- FAC-003-4 R4

PACIFICORP
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Wildfire Encroachment System Operations Procedure SOP-203

Document Information	
Author:	Erik Brookhouse
Owner (Position):	VP, System Operations
Approval:	SVP, Power Delivery
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	Confidential	X	Internal
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			BES Cyber System Information (BCSI)

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Revision Log		
0	6/30/2023	Preliminary draft
1	10/24/2023	Final draft for approval
2	1/23/2024	New format
3	5/14/2024	Update distances and add restoration section
4	5/31/2024	Update to Table 1 criteria for de-energization, added that company resource can be used for de-energization, instead of SCADA, if within a 15-minute window, added Table 2 criteria for patrols before re-energization
5	6/14/2024	Checklist update
6	6/25/2024	Updated narrative for duration of de-energization process for wildfires reported during certain wildfire risk conditions
7	4/25/2025	2025 update – Amended encroachment thresholds with executive review and approval
8	5/1/2025	Technical writing review and associated modifications

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Wildfire Encroachment System Operations Procedure SOP-203

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PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Wildfire Encroachment System Operations Procedure

SOP-203

1. PURPOSE

This document defines PacifiCorp's escalation and response protocols when a wildfire is approaching or broaching PacifiCorp's transmission and/or distribution facilities thresholds. As set forth in sections 7 and 8, IMMEDIATE ACTION…, this system operations procedure (SOP) requires de-energization of electric utility assets when a wildfire meeting the definition in Section 4 is within defined distances of PacifiCorp assets. Reference Section 9, MONITORING AND REPORTING, for wildfires that are outside the defined distances that require immediate monitoring and tracking. This procedure is not applicable for a natural area planned, controlled, or prescribed burn (fire) unless the burn becomes uncontrolled and meets the definition of a wildfire in Section 4.

2. REFERENCES

PAC-1000	Operating Transmission and Distribution Assets During Periods of Elevated Wildfire Risk
SOP-200	Operating Bulk Electric System Assets During Identified Wildfire Risk Procedure
SOP-201	Operating Sub-Transmission Assets During Identified Wildfire Risk Procedure
SOP-202	Operating Distribution Assets During Identified Wildfire Risk Procedure
SOP-204	Emergency De-energization Request Procedure
SOP-POL-007	PacifiCorp Emergency Operating Plan

3. COMMON ACRONYMS

BES	Bulk Electric System
ECC	Emergency Coordination Center
FEA	Fire Encroachment Analytics
FERM	Fire & Emergency Response Manager
FHCA	Fire High Consequence Area
IOU	Investor-Owned Utility
OMS	Outage Management System
PUD	Public Utility District
RC	Reliability Coordinator
SOP	System Operations Procedure
T&D	Transmission and Distribution
WIC	Wildfire Intelligence Center

4. DEFINITIONS

Wildfire – Is an uncontrolled and unpredictable wildland vegetation fire that burns in areas, including inside or adjacent to urban settings.

5. SCOPE

Wildfires can spread and move quickly based on many variables. This SOP is designed to facilitate emergency de-energization of electric utility assets within pre-identified safety buffers to minimize additional fire ignitions, create a safe environment for firefighting activities, and support the safety of potentially impacted communities. The policy outlines boundary distances for de-energization and offers a checklist to facilitate re-energization and reporting and communication protocols.

6. THREAT ASSESSMENT, CREDIBITY, AND DETERMINATION OF ACTION

The Wildfire Intelligence Center (WIC) and fire emergency response managers (FERM) utilize multiple technologies (wildfire cameras, fire agency application program interfaces [API], satellite hot-spot detection, fire / emergency dispatch monitoring, etc.) to support early wildfire detection and determination of general location. The WIC will establish credibility of all identified ignitions, regardless of input source, to determine if action is required—except when ***IMMEDIATE*** de-energization is required as identified in Table 1.

PacifiCorp assets within the wildfire encroachment boundary distances identified in Table 1 shall be de-energized when a credible threat appears without suppression activity, on-site resources, or intelligence to defer de-energization. **This includes joint- or foreign-owned assets under the operational control of PacifiCorp.** If the WIC can verify wildfire suppression, spread away from assets, and confirm there will be no impact to assets, with resources on-site to provide iterative intelligence, then any potential de-energization will be guided by their feedback and not the distances provided in Table 1 below.

Internal avenues for credible wildfire information that can support the system operators, within the distance and timeline threshold established, include 911, the WIC, FERM, T&D field operations, emergency management, grid operations, and customer service. The wind speed information at the fire location or nearest weather station will be obtained using PacificPowerWeather.com or RockyMountainPowerWeather.com before de-energization to determine which wildfire encroachment boundary applies.

Encroachment de-energization is not required when Non-Wildfire Operations (dark green) or Low Risk (light green) with sustained wind speed less than 15 mph match the conditions identified in Table 1.

Per Table 1, for Low (light green), Elevated (yellow), or Significant (orange) conditions that **DO NOT** require ***IMMEDIATE*** action, the de-energization process includes verifying wildfire conditions through the WIC, FERM, emergency management and local public safety partners; dispatching field resources; determining impacted area; and initiating notification process. The

de-energization process duration (including determination of credible wildfire) is expected to not exceed one hour.

If the WIC is unavailable, the system operator will contact the on-call emergency manager to evaluate credibility. Depending on the situation and availability of the on-call emergency manager, the system operator will facilitate de-energization and coordination of response resources.

7. IMMEDIATE ACTION: DUE TO FIRE LOCATION RELATIVE TO ASSETS

As outlined in Table 1, there are certain conditions that require the system operator to act ***IMMEDIATELY to de-energize*** all electrical assets supporting T&D facilities within the wildfire encroachment boundaries via the closest Supervisor Control and Data Acquisition (SCADA)-controllable device. In some cases, the SCADA-controllable device may require de-energization of transmission assets and could initially result in a larger-than-required de-energization area. A company resource qualified to operate field devices can be used in lieu of a SCADA-controllable device to conduct the de-energization if the de-energization can occur in approximately 15 minutes.

For all other weather conditions, if the WIC is unable to determine credibility, or **when data is not available or in doubt, system operators will de-energize.**

Table 1—Identified Wildfire Risk Level and Encroachment Boundary Distances

Fire Risk[3] (Fuel)	Sustained Wind Speed (mph)[2] < 15 Distance[5] (miles)	15 to 30 Distance[5] (miles)	> 30 Distance[5] (miles)
Non-Wildfire Operations	De-energization not required (DENR)[4]		
Low	DENR[4]	2	2
Elevated	2	3	4[1]
Significant	2	4[1]	6[1]
Extreme	Any wildfire within 6 miles[1]		

[1] Immediate de-energization
[2] Use pacificpowerweather.com and rockymountainpowerweather.com to determine wind speed
[3] As defined on the daily device weather risk matrix
[4] If de-energization is requested by emergency services (i.e., police, fire, local/state/federal agency, etc.) refer to SOP-204
[5] Distances are determined by assuming fire spread occurring at half the windspeed and allowing 15 minutes buffer before fire reaches assets

For example, opening only a substation distribution circuit breaker could satisfy the wildfire encroachment de-energization, but the closest SCADA-controlled device is at a transmission substation that will de-energize two distribution substations. In this case, even though more customers will be impacted, de-energize the transmission substation ***IMMEDIATELY*** as shown in Figure 1. Once personnel are available and visual assessment has been verified, the system operator has authority to begin restoration as outlined in Section 11.

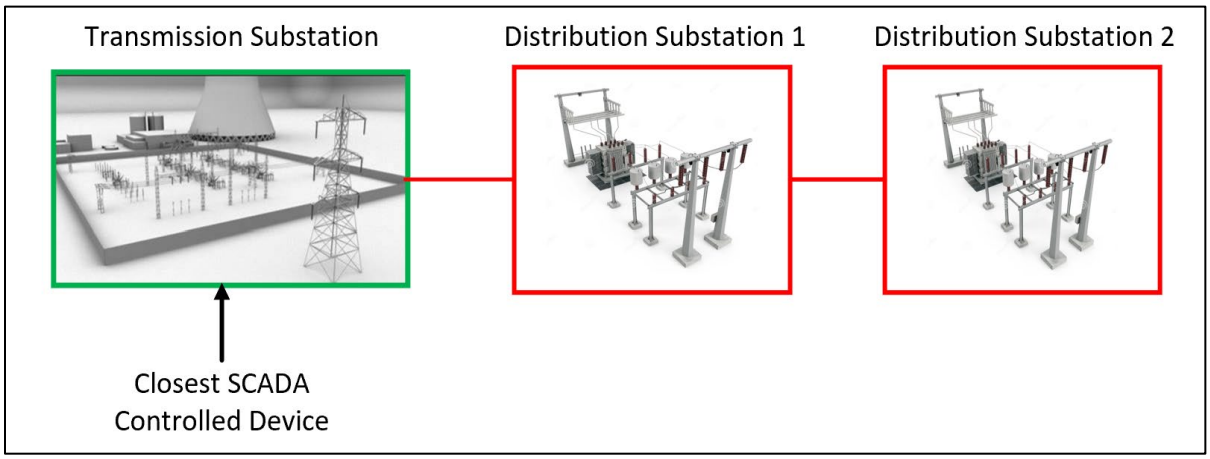

Figure 1—Wildfire Encroachment De-Energization Protocol

After an ***IMMEDIATE*** de-energization, if the process has not been initiated already, the system operator (grid and/or region) shall initiate or complete the following tasks:

1. The Control Center shall input actions into the Fire Encroachment Analytics (FEA) tool to provide common visibility of impacted structures and wildfire location.
2. The Control Center shall work with the WIC (Emergency Management if the WIC is unavailable) to validate fire information for credibility and determine whether company personnel are needed on site to assess the situation. If the wildfire is out upon arrival, T&D field personnel, FERM, or the WIC shall advise the system operator of the situation. The system operator shall begin the re-energization evaluation using the Re-Energization Checklist (see Appendix B).
3. The Control Center shall follow the standard notification operating procedures as outlined in SOP-POL-007 and applicable department briefing sheet procedures.
4. Grid Operations shall contact other impacted utilities (i.e., PUDs, IOUs, generators, etc.) and inform them of the situation per SOP-POL-007.
5. Grid Operations shall be required to gather generation MW lost, MW load loss, other impacted utilities, and any additional information required to understand the totality of the de-energization impact on the Bulk Electrical System (BES).
6. Region System Operations shall start the Wildfire Call Tracker per the requirements outlined in Section 10 if the WIC is unavailable.
7. The Control Center shall aggregate customer outage lists utilizing the FEA tool or other method if required and provide them to Customer Service Mission Control for customer communication.

Upon notification to the WIC and determination of action based upon credibility of wildfire threat (Section 6) or immediate action (Section 7) de-energization, the WIC shall initiate the following:

1. Begin the internal communication process outlined in Section 11, CUSTOMER AND STAKEHOLDER NOTIFICATIONS, and obtain information about the wildfire from local sources (FERM, emergency management, fire authority, emergency services and first

responders, etc.). This information will assist in the re-energization evaluation outlined in this document.

a. When fire conditions are ongoing and have no suppression, or as requested by the fire emergency response managers, the WIC will:

   i. Assess the wildfire environment and run a fire simulation.

   ii. If there is a transmission source de-energization with impact to customers, the BES, and/or generation, an Emergency Coordination Center (ECC) situational awareness call will be set up to determine the next steps.

b. If the information indicates the wildfire is out, the WIC will contact the system operator or the ECC executive (if the ECC is activated) so that re-energization activities can commence using the Re-Energization Checklist (shown in Appendix B).

c. If the information indicates the wildfire is active and the WIC, FERM or T&D field response has indicated it is not currently a threat to any asset, the WIC will begin the process outlined in Section 9, MONITORING AND REPORTING, while system operations completes the Re-Energization Checklist and initiates re-energization. Company personnel must remain on-site monitoring the wildfire unless directed otherwise.

8. IMMEDIATE ACTION: EMERGENCY DE-ENERGIZATION REQUESTS

When an immediate request to de-energize is received from company and/or emergency services personnel (e.g., police, fire, local/state/federal agency, etc.) for any fire that is not wildfire, the operator shall refer to SOP-204.

9. MONITORING AND REPORTING

This SOP provides specific buffer distances for different scenarios. If an active wildfire is encroaching or within a buffer distance, the line will be de-energized as outlined above. When the system is de-energized for wildfire encroachment, the system operator or reliability reporting personnel shall code the event in the Outage Management System (OMS) as follows:

- Cause Category: Planned
- Cause Code (new): Encroachment

The WIC is primarily responsible for monitoring any wildfire. The WIC, emergency management, or FERM may learn of new wildfires, and monitor known wildfires, through reporting from external sources and through monitoring of internal tools (e.g., wildfire cameras, satellite wildfire hot-spot warning, or other application alerts).

When system operations is notified of wildfire activity, they shall immediately notify the WIC (Emergency Management if the WIC is unavailable) and/or upon receiving notice of any new wildfire within 10 miles of any PacifiCorp assets. Wildfire response is contingent on the wildfire's distance from PacifiCorp assets, as follows:

- **More than 10 miles**. Wildfires more than 10 miles from the nearest PacifiCorp assets are monitored for potential growth and potential impact by the WIC. If the wildfire movement

is in the direction of company assets and is growing, a regular communication cadence to internal company personnel on the wildfire status will be established.

- **Greater than 6 up to 10 miles**. The WIC shall email a pre-identified list of company personnel of any new wildfire that is between 6 and 10 miles of PacifiCorp assets.

- **Preliminary Spread Assessment**. Upon receiving notice of a new wildfire, and fire conditions are ongoing and have no suppression, or as requested by FERM, the WIC will assess the wildfire environment and run a fire simulation. Fire simulations will be reviewed by FERM for evaluation of whether the fire will likely reach PacifiCorp within 36 hours. If confirmed, the WIC will start the notification process for possible de-energization.

10. WILDFIRE CALL TRACKER

The WIC shall open a Wildfire Call Tracker in FEA to initiate documentation for each verified wildfire. If wildfire contact with PacifiCorp assets is not likely to occur within 48 hours, the WIC shall continue to monitor the new wildfire and coordinate with FERMs if a new preliminary spread assessment is needed. The Wildfire Call Tracker includes the following information:

- Caller name, callback number and affiliation or position within PacifiCorp
- Incident location (address, GPS coordinates, or general location)
- Fire size, description of the fire including what it is burning in
- Proximity to nearest PacifiCorp asset(s), identifying asset information and description of assets
- What resources are on scene or ETA, and visible hazards
- Agency having jurisdiction
- PacifiCorp employee-provided information:
    - De-energized? If so, what circuits
    - Any notifications to System Operations or Grid Ops
    - Any local notifications, or are they in contact with local fire incident command
    - Current damage to assets and description
    - Status and monitoring capabilities of field personnel

The WIC will continue to monitor the wildfire and provide updates in FEA for situational awareness. The WIC will coordinate situational updates for notifications within the FEA platform. In conjunction with ongoing monitoring, the WIC shall:

- Coordinate with FERM, if necessary, regarding fire status to support updates to officials by regional business managers, emergency managers, etc.
- Coordinate with the on-scene field personnel as needed.
- Confer with the on-duty meteorologist to evaluate fire conditions and update fire spread assessments as needed.
- Update the Wildfire Call Tracker as needed.

- Manage ongoing wildfire status updates within FEA for T&D field operations, system operations, FERM, emergency management, and meteorology until there is no threat to PacifiCorp assets.

11. CUSTOMER AND STAKEHOLDER NOTIFICATIONS

For an ***IMMEDIATE*** (after-the-fact) or ***IMMINENT*** de-energization, the system operators will provide notice to on-call region and/or grid system operations management and the WIC, who will begin coordination with emergency management, FERM, meteorology, executive management, corporate communications, customer service, regional business managers, and T&D field operations.

System Operations

Department	Contact	Number
Emergency Management	24/7 On Duty – Pacific Power	503-331-4498
	24/7 On-Duty – Rocky Mountain Power	801-220-2057
Wildfire Intelligence Center	24/7 Operations	541-608-2390
Impacted Utilities		Based on location

System operations will follow standard internal outage notification process after de-energization, which will indicate it was an emergency de-energization due to an encroaching wildfire.

Internal Stakeholder Contacts

Department	Contact	Number
Executive Management	On-call ECC Executive	Refer to on-call schedule
T&D Field Operations	VP and Area Director	Based on location
System Operations	VP and Director, Region and Grid	Based on location
Corporate Communications	24/7 Hotline – Pacific Power	503-813-6018
	24/7 Hotline – Rocky Mountain Power	801-220-5018
Customer Service	Manager, Customer Service Mission Control	503-813-5087
Regional Business Manager(s)	Area Regional Business Manager	Based on location
Regulatory Affairs	VP Regulatory Affairs	Based on location
Government Affairs	VP Government Affairs	Based on location
Meteorology	24/7 On-Duty	503-331-4495

If time allows before de-energization, customer and stakeholder notification will be executed by the appropriate departments. If time does not allow, a post-event customer notification strategy will be utilized. Stakeholders include other utilities, the reliability coordinator, the state commission, and other government authorities.

12. RE-ENERGIZATION

As information is obtained concerning the wildfire event, it may be possible to begin re-energizing parts of, if not all of, the assets initially de-energized.

The system operator has authority to re-energize under the following conditions:

1. Assets that were de-energized based on a SCADA control location; once isolation is in place, the assets are no longer required to be de-energized.
2. System operator has completed the Re-Energization Checklist and has the authority to re-energize if all "YES/NO" questions on the checklist have been answered "YES."
3. When on-site response has deemed there is no current threat to company assets.

In all other cases, including a Re-Energization Checklist with even a single "NO," the system operator must obtain authorization to re-energize from a power delivery director or identified delegate.

The criteria in Table 2 shall be used to determine if a patrol is required before re-energization.

Table 2 – Criteria for Patrol Before Re-energization

#	Criteria	Patrol Required	Authority to Re-energize
1	If the Fire Risk Level is Extreme [RED]	Yes	ECC Executive
2	If the outage is longer than 3 hours	Yes	Operator
3	If fire reached company assets	Yes for assets the fire reached	Operator
4	If **outside encroachment boundary** **AND** Fire Risk is Significant [ORANGE] or lower **AND** outage is shorter than 3 hours	No	Operator
5	If **inside encroachment boundary** **AND** fire is out **AND** outage is shorter than 3 hours **AND** fire did not reach company assets	No	Operator
6	If **inside encroachment boundary** **AND** Fire is active	Yes Exception can be granted by a director	Operator for Fire Risk [Yellow] and below Director for Fire Risk [Orange]

Note: The 3 hours is in reference to distribution outages. Transmission outages do not have these criteria for determining the need for a patrol.

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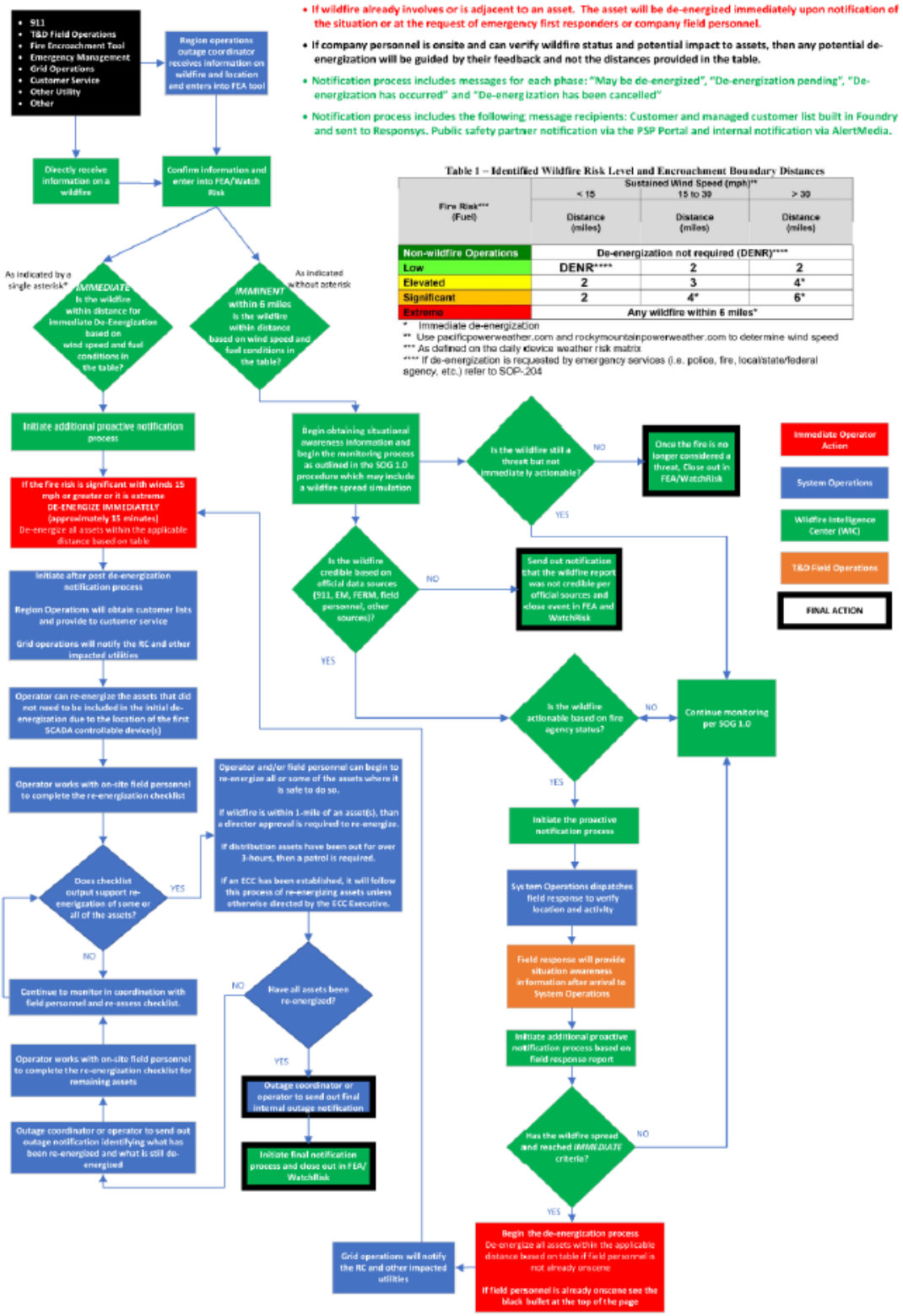
APPENDIX A: FLOWCHART FOR FIRE ENCROACHMENT ASSESSMENTS

Refer to PolicyTech for the full-size flowchart.



13. APPENDIX B: RE-ENERGIZATION CHECKLIST

The table below is for example only. For the most current version, refer to separate PolicyTech uploaded checklist "SOP-203 Re-Energization Checklist."

APPENDIX B: RE-ENERGIZATION CHECKLIST		YES/NO
Date:		
Fire Name:		
WEATHER OBSERVATIONS	**ANSWER-COMMENTS**	
District Weather Matrix Color		
District Fire Risk Matrix Color		
Is it Dark Green, Light Green, Yellow, or Orange with winds less than 15 mph?		
Current Wind Conditions (Sustained and Gust information from nearest weather station)		
Current Weather Conditions (i.e. rain, thunderstorms, sunny, etc.)		
No thunderstorms in the area?		
WILDFIRE OBSERVATIONS	**ANSWER-COMMENTS**	
Is the wildfire controlled?		
If YES		
Who confirmed?		
On-site Field Personnel		
On-site Fire Agency		
Company Emergency Manager Name and provide EM source of information (i.e. County EM, Fire Agency, etc.)		
Other (Name and Agency)		
Can damaged asset(s) be isolated to support safe restoration?		
If NO		
Field Observed Fuel Type (Grass, Forest (Trees), etc.)		
Field Observed Terrain (Flat, Steep, Combination, etc.)		
Is the Wildfire beyond one mile of asset(s)?		
Wildfire proximity to asset or assets (Miles*)		
Is the Wildfire moving away from asset(s)?		
Direction of movement		
Are fire agencies on scene?		
On-site Fire Agency Name (if known and if multiple agencies just indicate multiple)		
If the fire is controlled, who confirmed? (Name and Agency)		
Can asset(s) not in the path of the wildfire be safely re-energized? *Isolation of the asset(s) min the path of the wildfire may support some level of restoration.*		
Can damaged asset(s) be isolated to support safe restoration?		

*If wildfire is within 1 mile of the asset(s) then a director must approve re-energization.

NOTE: If any of the following YES-NO answers above are a "NO" then a Power Delivery Director approval is required to re-energize.

2025 Public Safety Power Shutoff Execution Playbook

Document Owner: The emergency management team is responsible for maintaining this document. This includes scheduling annual reviews and exercises, updating content based on annual reviews and exercises, and redistributing new versions to document stakeholders.

The plan will be reviewed and exercised annually. The scale of the exercise will be determined by the Power Delivery executive leadership in coordination with emergency management personnel and key leadership.

Author: PacifiCorp Emergency Management Version: 5.0 Origination Date: May 10, 2019 Last Revision: April 10, 2025	Exercise Last Exercise Date(s): May 22 and June 25, 2024 Last Exercise Type: Functional Next Exercise Date: 2025 Next Exercise Type: Tabletop

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Record of Revisions

Date of Revision	Activity	Summary of Changes	Reviewers/ Approvers
Dec 2022	Plan revised	Significant revisions	PacifiCorp Emergency Management
July 2023	Plan review and revision	Incorporate lessons learned from 2023 PSPS exercise series: • Add Appendix E: State Specific guidance • Add Cooperators Call briefing template reference • Clarify CRC deployment ownership • Change color code for PSPS Restoration to match PSP Portal • General document formatting updates	PacifiCorp Emergency Management
February 2024	Plan review and revision	• Glossary update to match appropriate acronyms within the document • Position duty adjustments to meet new terminology and responsibilities • Removed organization structure charts • Refined Joint Information Team responsibilities	PacifiCorp Emergency Management
March 2025	Plan review and revision	• Glossary update to match appropriate acronyms within the document • Position duty adjustments to meet new terminology and responsibilities • Additional positions added • Implemented a master order of roles and responsibilities • Separated section 6.1 into two - 6.1 and 6.2 • Updated State specific reporting requirements for CA, added ID and WY reporting requirements	PacifiCorp Emergency Management

2 PACIFICORP ACRONYMS

AAR – After Action Report

AFN – Access and Functional Needs

CRC – Community Resource Center

DOC – Department Operations Center

DOT – Department of Transportation

ECC – Emergency Coordination Center

EFR – Elevated Fire Risk

EM – Emergency Management

EOC – Emergency Operations Center

EPG – Executive Policy Group

ETR – Estimated Time of Restoration

FEMA – Federal Emergency Management Agency

GIS – Geographic Information System

ICS – Incident Command System

IP – Improvement Plan

JIT- Joint Information Team

MBL – Medical Baseline

PIO – Public Information Officer

PP – Pacific Power

PSP – Public Safety Partner

PSPS – Public Safety Power Shutoff

PUC – Public Utilities Commission

RBM – Regional Business Manager

RMP – Rocky Mountain Power

WIC – Wildfire Intelligence Center

WRMAA – Western Region Mutual Assistance Agreement

3 OVERVIEW

3.1 PURPOSE

The Public Safety Power Shutoff (PSPS) Playbook, referred to as the "playbook" throughout this document, is intended to provide the **minimum** guidelines for a planned de-energization (Public Safety Power Shutoff) of energized facilities when extreme weather or other conditions pose an imminent safety threat to persons and/or property.

3.2 ASSUMPTIONS, LIMITATIONS, AND PLANNING CONSIDERATIONS

3.2.1 ASSUMPTIONS

The following planning assumptions include expected effects to the company or its assets in the event of a PSPS event:

- A planned de-energization is a last resort measure to reduce public safety risk.
- In the event of an emergency, a decision (i.e., to protect fire response personnel or to protect company assets from fire damage) might be made without complying with the notification and outreach sections of this plan.
- This playbook primarily allows for a proactive decision to be made, to implement a planned PSPS event.
- While unavoidably disrupting electrical service, a planned PSPS event may be warranted to reduce risk of energized facilities being involved in a public safety incident under extreme conditions (i.e., weather, flooding, etc.).
- PSPS events are dynamic in nature and may require additional, or a variance in steps, as dictated by the event.

3.2.2 LIMITATIONS

The following planning limitations outline actions either required (must do), or prohibited (cannot do), in the event of a PSPS event:

- In the event of a de-energization, it is imperative the Emergency Coordination Center (ECC) initiate internal preparation measures and facilitate external coordination with appropriate public safety partners, key account holders, and regulatory agencies.
- Business units may be required to prepare to allocate limited resources.
- Applicable by state, regulatory stipulations will be fulfilled as required.
- This playbook does not supersede the general authority of the company to de-energize a powerline during an emergency.
- PSPS response objectives to ensure life-safety, ensure employee welfare and continuous coordination and communication with affected customers will be maintained throughout a PSPS Watch, Warning, Execution and Restoration.

3.2.3 PLANNING CONSIDERATIONS

The following must be considered when planning for a PSPS event:

- Additional guidelines may be required as part of a specific state event mitigation plan (i.e., wildfire).
- This playbook may be activated for any public safety incident which could be mitigated by de-energization of specific energized infrastructure.

4 SITUATION OVERVIEW

The company utilizes weather forecasts and other situational awareness information to identify when a potential PSPS event may be warranted. Based on the best available weather forecast and other relevant situational awareness information, senior management can initiate a PSPS event.

Upon agreement by executive management to initiate PSPS actions, the ECC will be activated. The ECC Staff will then prepare a tailored PSPS Plan, which at a **minimum** may include:

- Forecasted date and time that the de-energization event will start.
- Estimated duration of the event.
- Date and time that affected customers will be notified under a proposed customer notification plan.
- Critical customers and facilities on the circuit such as hospitals, emergency centers, and water providers, wastewater treatment plants that will be impacted.
- With respect to each circuit or portion of a circuit planned for de-energization, a description of the circumstances that give rise to the need to de-energize with specific focus on how it creates an “imminent and significant risk to persons and/or property.”
- A description of measures considered as an alternative to de-energization and why such measures alone are insufficient.
- A description of the public safety benefits the company hopes to achieve by de-energizing the applicable electrical facilities.
- A description of proposed efforts to mitigate the adverse impacts on customers and communities impacted by de-energization; and
- The proposed date and time for notifying the appropriate commission staff.
- Additional information may be required as part of a specific state event mitigation plan.

Once the PSPS Plan is ready for implementation, the ECC will activate a MSTeams meeting, or company conference bridge if MSTeams is unavailable and invite company participants or their designated representative.

The PSPS Plan may be modified based on the discussion during the call.

4.1 PSPS Weather Monitoring and Review

During fire season, as needed, a situational monitoring call may be conducted when the forecast indicates the potential for PSPS actions. A decision to activate the ECC may be made within the situational monitoring call or may be initiated separately.

The following considerations are part of the decision process to initiate PSPS actions:

- **Location:** Are powerlines within an area where local fuels will allow for ignition and spread of a wildfire? Is the wildfire risk extreme?
- **Weather:** Do current and/or forecasted wind conditions pose an increased risk of wind or vegetation related outages?
- **Duration:** Is the duration and extent of these conditions sustained and not momentary or hyperlocal?
- **Public Safety:** Are any ongoing public safety incidents going to be impacted by PSPS execution?
- **Field Observations:** Do field observations indicate an imminent threat to powerlines, are fire response resources limited, or there are minimal ingress or egress routes?

4.2 Circuit Situational Monitoring

Prior to the activation of the PSPS, the Area/District Manager or designee may dispatch circuit crews to the impacted areas to complete a weather and/or situational assessment and a patrol of the targeted circuits using the 069 Procedure – Condition Codes. Feedback will be provided to the ECC via approved process. *Reference PacifiCorp Transmission Forms, Policies, and Procedures and 069 Procedure – Condition Codes.*

4.3 External Coordination

Strong partnerships between the utility and local public safety, public health providers, other utilities, and emergency management agencies are essential for effective coordination in any event that impacts the community. PacifiCorp will serve as the initiating agency in the event of a PSPS and will coordinate with all local agencies and Tribal Nations as appropriate. The utility will consider the expertise and recommendations offered by state and local emergency management agencies. Any non-outage related issues or incidents that arise during a PSPS will be handled by local emergency management and public safety.

PacifiCorp emergency management staff will maintain regular outreach during the event. PacifiCorp's Wildfire Intelligence Center (WIC) will coordinate with emergency management to maintain PacifiCorp's Public Safety Portal (PSP Portal) and send communications to registered public safety partners and critical facilities via the PSP Portal. Additionally, as needed, PacifiCorp personnel may be dispatched to the affected State or County Emergency Operations Centers in the role of Agency Representative to serve as a conduit for information sharing.

To help PacifiCorp understand local sensitivities and concerns during a PSPS, PacifiCorp will typically discuss the critical infrastructure affected with the local emergency management agencies. This information adds to the situational awareness of PacifiCorp's incident command personnel before the event's initiation. State and county specific notification requirements and information can be found in Appendix E of this document.

PacifiCorp will conduct outreach to adjacent utilities as appropriate based on the event's circumstances. Other utility contact information can be found within mutual assistance directories or the use of the "in case of crisis" application which is an electronic directory of all Western Region Mutual Assistance Agreement members' utility points of contact, internal directory as created for smaller neighboring utilities, and through ESF-12 (Energy Support Function) requests for coordination.

Effective communication is essential in any incident that impacts the public. PacifiCorp's Joint Information Team (JIT) will coordinate local communication from the ECC. Event update meetings will be held as needed with an option to join remotely. In addition, should a Community Resource Center (CRC), as outlined in the Community Resource Center Playbook, be established, company representatives will be present to communicate with and assist community members. The communication plan can be found in Appendix D of this document.

When feasible, the decision to activate a Community Resource Center should be made at the 48-hour point. If 48-hour notice is not feasible, a CRC decision should be made at least within the 24-hour point, because a minimum of a 24-hour notice is typically needed to successfully mobilize a Community Resource Center (see PacifiCorp's CRC Playbook for more detail).

4.4 Pre-Event Notification to Affected Customers and Other Stakeholders

PacifiCorp's meteorology team assesses wildfire risk across the service territory daily. Inputs for assessing wildfire risk include weather conditions, the dryness of fuels, wildfire risk modeling, and other inputs such as National Weather Service or Geographic Area Coordination Center wildfire potential forecasts. Public safety power shutoffs may be needed when areas are assessed to have extreme wildfire risk.

When the ECC is activated, a member of PacifiCorp's emergency management staff will assume the position of the ECC Manager. Upon direction from emergency management, the Wildfire Intelligence Center (WIC) will schedule a coordination call and notify the appropriate personnel of the activation through established distribution lists.

The ECC Manager will facilitate coordination calls. Goals of the call include identifying and prioritizing actionable items; and modification to the PSPS Plan as needed for the specific event. Once the plan has been approved and adopted, it will receive approval from the ECC Executive and Department Operations Center (DOC) Section Chief.

PSPS Timeline	
Level	**Description**
PSPS Watch	Public safety circumstances require enhanced situational monitoring is required and a de-energization event is possible to occur
PSPS Warning	Public safety circumstances are such that a de-energization event will likely occur
PSPS Cancellation	Public safety circumstances are such that PSPS actions are no longer necessary, make notifications the same as event end. This may occur prior to execution during watch or warning phases.
PSPS Execution	Public safety circumstances are such that de-energization actions are in progress
PSPS Restoration	Public safety circumstances are such that restoration actions have begun
PSPS Event End	All restoration is complete

After adoption of a PSPS Plan, before the de-energization event is initiated, the company will make reasonable attempts to notify affected customers and other stakeholders of the planned event. As situations can be dynamic, the timeframes outlined in the above table are subject to change and may be adjusted for each specific event. If an individual(s) responsible for notifications did not participate in the initial call, the ECC will ensure the plan is immediately delivered to every individual (or designee). Additional notification obligations may be required as outlined in each state wildfire mitigation plan.

In addition to the normal automatic notification tools, customer service will attempt to make personal phone calls to customers in the company database with access or functional needs (AFN). Customer service tracks if a positive confirmation of contact was made with each AFN customer. The results of the contact are reported to the ECC Executive. If an AFN customer needs additional assistance, the AFN Coordinator coordinates with customer service, the ECC Joint Information Team and the ECC Liaison Officer to quickly relay the information to local public safety partners, as appropriate. Such coordination may lead to a wellness check.

4.5 DE-ENERGIZATION

Region System Operations will develop the switching plan(s) for the PSPS execution after adoption of the PSPS plan. A final review of the switching plans by Power Delivery will be completed before execution by the ECC. The ECC Executive provides the final approval to initiate a PSPS. After the final approval is received, the designated Power Delivery Department Operations Center Section Chief receives instruction from the ECC to execute de-energization; the appropriate operator(s) will begin switching activities with field personnel. Data regarding

areas impacted, de-energization and restoration times will be captured in the data collection table (Attachment F).Foundry PSPS Operational Dashboard.

4.6 RESTORATION

The ECC will notify the Power Delivery Department Operations Section Chief that the conditions necessitating the planned PSPS have subsided and prepare to initiate restoration of the affected facilities once directed to restore.

Before re-energizing any facilities (line, substation, etc.), the Power Delivery Department Operation Center will direct field personnel to begin assessing the deenergized circuits generally through ground or air patrols. As part of the patrol and inspection, field personnel must document all damage to PacifiCorp's facilities in the de-energized areas.

After receiving confirmation that a line is ready for restoration based on existing guidelines, the responsible region operator shall restore the applicable lines(s) or portion(s) of a line (distribution and/or transmission), facilities (i.e., substations), and log the date and time each facility (line, portion of line, substation, etc.) was re-energized.

4.7 EVENT END

Marked by cancellation without de-energization, or upon restoration of customers affected by the PSPS event and begin the After-Action Report (AAR) process. These actions include deactivating the ECC, gathering all notes and materials for inclusion in the AAR, notification to partners of response termination in the PSP Portal, and creating, and tracking to completion of the AAR and Improvement Plan (IP).

5 ROLES AND RESPONSIBILITIES

Roles, responsibilities, and protocols for managing an event or incident are defined in the PacifiCorp Emergency Response Plan (ERP) which follows FEMA guidelines and bases the PacifiCorp response framework on the principles of the National Incident Management System (NIMS). Information and responsibilities included in this document are meant as a supplement to PacifiCorp's all-hazards incident management structure.

5.1 OVERVIEW

The ECC provides coordination and support to the Power Delivery Department Operations Center and tactical response resources and reports current situational information to the Executive Policy Group and/or Operational Leadership Group. The ECC organizational structure is designed to be scalable based on situational needs and follows the established structure as outlined in the Emergency Response Plan and related functional annexes.

6 PSPS CHECKLISTS

The checklist tables below are broken out by timeframes for PSPS Watch, Warning, Cancellation, Execution, Restoration and Event End. The tables below identify required activities specific to a PSPS event. The PSPS Data Reporting Template.xlsx defines PSPS-specific documentation requirements and timeframes.

6.1 PSPS WATCH | 7-4 DAYS PRIOR

Public safety circumstances require enhanced situational monitoring, and a de-energization event is possible to occur. This phase includes internal preparation measures as well as external coordination with appropriate public safety partners, key account holders, and regulatory agencies.			
Objectives			
• Ensure life-safety • Ensure employee welfare • Continuous coordination and communication with affected customers			
	Actions	**Responsible**	**Complete**
PSPS WATCH 7-4 DAYS PRIOR	☐ Receive forecast notification and notify appropriate personnel	T&D VP or Director	
	☐ Approve activation of PSPS Execution Playbook and associated actions	SVP Power Delivery (or delegate)	
	☐ Notify appropriate county, state, and Tribal emergency management agencies and ESF-12 (Energy) as appropriate ☐ Gather local situational information from impacted emergency management agencies ☐ Initiate pending event in Foundry PSPS Operational Dashboard	Emergency Management	
	☐ Receive forecast notification and notify appropriate personnel ☐ Under direction from emergency management, initiate and coordinate decision making conference call ☐ Initiate pending event in the Public Safety Portal	Wildfire Intelligence Center (WIC)	
	☐ Monitor latest meteorological data	Meteorology	

PSPS WATCH 7-4 DAYS PRIOR	☐ Provide situational awareness updates as needed or requested ☐ Identify potential areas at risk for PSPS ☐ Consult meteorology specific PSPS Operations Checklist (Included in Appendix)		
	☐ Participate in initial decision-making call ☐ Assume Response Organization roles	All	

6.2 PSPS WATCH | 7-4 DAYS PRIOR: ECC PRE-ACTIVATION PREPARATION

Public safety circumstances require enhanced situational monitoring is required and a de-energization event is possible to occur. This phase includes internal preparation measures as well as external coordination with appropriate public safety partners, key account holders and regulatory agencies. Business units will begin to review and assume potential ECC roles. ECC organizational structure is scalable based on the complexity of the incident.

The ECC may be activated at any point in the 7-4-day timeframe leading up to the event. ECC activation is approved by senior leadership that will assume the ECC Executive role.

The below checklist items outline the transition from normal business titles to assume EPG/ECC/DOC roles in preparation of ECC activation.

Objectives

- Ensure life-safety
- Ensure employee welfare
- Continuous coordination and communication with affected customers

	Actions	Responsible	Complete
PSPS WATCH **7-4 DAYS PRIOR**	☐ Activate Department Operations Center and assume command of situation until termination Assume role of DOC Section Chief	T&D VP or Director	
	☐ Assume role of Generation or Renewables DOC Chief (if applicable) ☐ Identify effects on generation capability ☐ Prepare affected plant personnel for de-energization ☐ Develop restoration plan	Generation or Renewables VP	
	☐ Region System Operations assumes DOC and ECC roles ☐ Obtain the following data: • Receive identified circuits list from Meteorology • Create impacted critical customer list ☐ Create impacted customer list	System Operations Directors	
	☐ Communicate PSPS Watch with vegetation staff ○ Update resource list ○ Coordinate with operations to support as needed	Vegetation Management Director	
	☐ Direct activation of the DOC and ECC for support operations ☐ Approve / appoint role of ECC Executive until termination	SVP Power Delivery (or delegate)	

PSPS WATCH **7-4 DAYS PRIOR**	*Note: Consider additional staff for weather monitoring, switching plan development, and engineering support*		
	☐ Assume role of ECC Manager ☐ Update pending event in Foundry PSPS Operational Dashboard	Emergency Management	
	☐ Assume role of EPG Director (if activated)	CEO (or delegate)	
	☐ Assume role of ECC Liaison Officer ☐ Continue coordination with county, state, and Tribal emergency management agencies and ESF-12 as appropriate ☐ Notify CRC vendor of potential response ○ *See CRC Playbook for specific information*	Emergency Management	
	☐ Assume role of IM Specialist ☐ Begin compiling data into PUC post event reports as applicable	Emergency Management	
	☐ Assume the role of Meteorology Specialist ☐ Monitor weather forecasts ☐ Provide weather briefings ☐ Identify potential circuits at risk	Meteorology	
	☐ Assume Joint Information Team (JIT) Lead ☐ Ensure adequate internal staffing for all external communications functions ☐ Review PSPS messaging and talking points	Corporate Communications	
	☐ Assume Role of RBM Coordinator ☐ Establish CRC staffing plan ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs ☐ Coordinate outreach to Tribal Nations with the Tribal Liaison/Government Affairs	Regional Business Manager	
	☐ Assume role of Mission Control	Customer Service	
	☐ Assume Role of AFN Coordinator ☐ Coordinate with Mission Control to identify impacted medical and other AFN customers in database	AFN Program Manager	

PSPS WATCH **7-4 DAYS PRIOR**	☐ Coordinate with Liaison Officer on notifications to local and state AFN service provider partners		
	☐ Assume role of Regulatory Coordinator ☐ Communicate with appropriate state regulatory agencies as required	Regulatory Affairs	
	☐ Assume role of Government Affairs Coordinator ☐ Communicate with governor's office and appropriate state agencies and elected officials as required ☐ Communicate with Tribal Nations via the Tribal Affairs Coordinator and Regional Business Managers	Government Affairs Coordinator	

6.3 PSPS WATCH | 72-48 HOURS PRIOR

Public safety circumstances require enhanced situational monitoring is required and a de-energization event is possible to occur. This phase includes internal preparation measures as well as external coordination with appropriate public safety partners, key account holders and regulatory agencies. Appropriate coordination calls have been scheduled or commenced, and ECC-specific positions are filled.			
Objectives • Ensure life-safety • Ensure employee welfare • Continuous coordination and communication with affected customers			
	Actions	**Responsible**	**Complete**
PSPS WATCH **72-48 HOURS PRIOR**	☐ Manage assets within and outside affected area	Power Delivery DOC Chief	
	☐ Secure necessary field resources to support effort ☐ Manage assets within and outside affected area	Impacted Wires Director	
	☐ Provide resources to support effort as requested ☐ Secure necessary field resources to support efforts and day-to-day operations	Supporting Wires Director	
	☐ Identify potential effects and mitigation strategies on generation assets ☐ Prepare affected plant personnel for de-energization (if applicable) ☐ Develop restoration plan (if needed)	Generation or Renewables DOC Chief	
	☐ Pull customer data & provide to ECC & Mission Control ☐ Create switching plans for engineering to review ☐ Review and ensure adequate staffing	System Operations	
	☐ Operational support ○ Coordinate with operations to support as needed	Vegetation Management	
	☐ Maintain overall leadership of the ECC ☐ Provide updates to the EPG Director	ECC Executive	
	☐ Receive updates from the ECC Executive and provide guidance as needed	EPG Director/ CEO	
	☐ Develop staffing plan for ECC	ECC Manager	

PSPS WATCH **72-48 HOURS PRIOR**	☐ Ensure Finance Section Chief has created a Work Order and publish for use during event ☐ Update potential event in Foundry PSPS Operational Dashboard		
	☐ Update appropriate county and state management agencies including ESF-12, and plan cooperator call cadence (where required) cooperators call template ☐ Update appropriate Tribal emergency management offices, and include with cooperator call, or coordinate a separate call. ☐ Review potential outreach activities, including, but not limited to: ○ Variable messaging signs through DOT ○ County Emergency Management Agency messaging support ○ State Emergency Management Agency messaging support ○ Tribal Emergency Management Agency support ☐ Coordinate potential CRC locations with local public safety partners and RBM ☐ For events affecting multiple utilities, request State ESF-12 establish regular coordination calls among all affected utilities and the appropriate PUC/State Emergency Management Agency	ECC Liaison Officer	
	☐ Start compiling the post event report documentation	IM Specialist	
	☐ Create event areas within the Public Safety Portal ☐ Coordinate messaging through the Public Safety Portal as requested by ECC Manager ☐ PSPS website goes live Public Safety Power Shutoff	WIC	
	☐ Monitor latest meteorological data ☐ Provide situational awareness updates ☐ Refine potential areas at PSPS risk in PSPS circuit forecast editor tool ☐ Develop personnel schedule to cover the event ☐ Assess potential need for portable weather station deployment	Meteorology	
	☐ Start tracking event costs	Finance Chief	
	☐ Contact contracted translation services to ensure adequate staffing ☐ Internal distribution of PSPS talking points ☐ Monitor and respond to media	JIT	
	☐ Confirm CRC staffing plan	RBM Coordinator	

PSPS WATCH **72-48 HOURS PRIOR**	☐ Coordinate CRC logistics with ECC Liaison ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations		
	☐ Review call center staffing and checking on-call lists to ensure adequate staffing during PSPS event	Mission Control	
	☐ Coordinate with Liaison Officer to include appropriate local and state AFN partners in cooperator call ☐ Review potential outreach activities, in coordination with EM Liaison, with: ○ Local and state AFN service providers ○ 211 messaging, as available and appropriate ☐ Engage in CRC planning with EM Liaison and RBMs ☐ Coordinate with T&D on portable household generators	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with potentially impacted Tribes ☐ Coordinate with potentially impacted Tribes to address resource needs (with RBM Coordinator)	Tribal Affairs Coordinator	

6.4 PSPS Warning | 48-24 Hours Prior

Public safety weather forecasts are such that a de-energization event will likely occur. This phase internal preparation and external coordination continue. Customer and public notification begin. Appropriate coordination calls have been scheduled or commenced, and ECC-specific positions are filled.

Objectives

- Ensure life-safety
- Ensure employee welfare
- Continuous coordination and communication with affected customers

	Actions	Responsible	Complete
PSPS WARNING **48-24 HOURS PRIOR**	☐ Manage assets and resources within and outside affected area	Power Delivery DOC Chief	
	☐ Review and finalize switching orders based on known circumstances	System Operations	
	☐ Operational support o Coordinate with operations to support as needed	Vegetation Management	
	☐ Direct overall ECC operation ☐ Provide updates to the EPG Director	ECC Executive	
	☐ Receive updates from the ECC Executive and provide guidance as needed (if activated)	EPG Director/CEO	
	☐ Update event in Foundry PSPS Dashboard	ECC Manager	
	☐ Initiate appropriate Emergency Management Agency outreach (templates in Appendix A References) ☐ Request partners continue outreach to include: o Variable messaging signs through DOT ☐ State, County and Tribal Emergency Management Agency messaging support ☐ Continue CRC coordination with vendor and RBM Coordinator	ECC Liaison Officer	
	☐ Continue compiling documentation for PUC post event report	IM Specialist	
	☐ Update the event in PSP Portal as needed ☐ Coordinate messaging through the PSP Portal as needed ☐ Continue updating PSPS Website	WIC	
	☐ Continuously monitor latest meteorological data	Meteorology	

PSPS WARNING **48-24 HOURS PRIOR**	☐ Provide situational awareness briefings		
	☐ Initiate appropriate customer, community-based organization, media, and business outreach ☐ Coordination communication cadence and content ☐ Notification posted on homepage and social media ☐ Press release ready for distribution ☐ Ensure official communications channels have consistent messaging ☐ Begin JIT coordination calls	JIT	
	☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers ☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media	Mission Control	
	☐ Coordinate with Mission Control, Liaison Officer and local public safety partners to address unmet medical/AFN customer needs ☐ Request AFN partners continue outreach to include: o Local and state networks o 211 messaging, as available and appropriate ☐ Coordinate with Liaison Officer and RBMs on medical/AFN needs for CRCs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with potentially impacted Tribes ☐ Coordinate with potentially impacted Tribes to address resource needs (work with RBM Coordinator)	Tribal Affairs Coordinator	

6.5 PSPS Warning | 24 Hours Prior

Public safety weather forecasts are such that a de-energization event will likely occur. This phase internal preparation and external coordination continue. Customer and public notifications continue at the prescribed cadence. Appropriate coordination calls have been scheduled or commenced, and ECC-specific positions are filled.			
Objectives • Ensure life-safety • Ensure employee welfare • Continuous coordination and communication with affected customers			
	Actions	**Responsible**	**Complete**
PSPS WARNING **24 HOURS PRIOR**	☐ Initiate resource deployment for de-energization and restoration tasks ☐ Manage assets and resources within and outside the affected area	Power Delivery DOC Chief	
	☐ Pre-position resources to appropriate circuits for de-energization and restoration	Power Delivery Field Incident Command	
	☐ Identify effects on generation capability ☐ Prepare affected plant personnel for de-energization (if applicable) ☐ Develop restoration plan (if needed)	Generation or Renewables DOC Chief	
	☐ Engineering review to support switching plan	Engineering	
	☐ Operational support o Coordinate with operations to support as needed	Vegetation Management	
	☐ Direct overall ECC operation ☐ Provide updates to the EPG Director	ECC Executive	
	☐ Receive updates from the ECC Executive and provide guidance as needed	EPG Director/ CEO	
	☐ Update potential event in Foundry PSPS Operational Dashboard	ECC Manager	

PSPS WARNING **24 HOURS PRIOR**	☐ Continue appropriate county, state appropriate emergency management agency's request to include • Variable messaging signs through DOT • State, County and Tribal Emergency Management Agency messaging support ☐ Provide Agency Representative to Local EOC as available/requested ☐ Finalize CRC mobilization ○ *See CRC Playbook for specific information*	ECC Liaison Officer	
	☐ Continue compiling data into PUC post event reports	IM Specialist	
	☐ Update the event in PSP Portal as needed ☐ Coordinate messaging through the PSP Portal as needed ☐ Continue updating PSPS Website	WIC	
	☐ Continuously monitor latest meteorological data ☐ Provide situational awareness briefings ☐ Make final revisions to potential PSPS circuits at risk ☐ Initialize meteorology event log	Meteorology	
	☐ Continue appropriate customer, AFN service providers , Tribal, media, and business outreach ☐ Coordination communication cadence and content ☐ Notification updates posted on homepage, social media, and PSPS webpage as needed ☐ Issue a press statement/release ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Activate CRC staffing plan ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers	Mission Control	

PSPS WARNING **24 HOURS PRIOR**	☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media		
	☐ Coordinate with local and state AFN service providers on local resources ☐ Coordinate with mission control, Liaison Officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with potentially impacted Tribes ☐ Coordinate with potentially impacted Tribes to address resource needs (work with RBM Coordinator)	Tribal Affairs Coordinator	

6.6 PSPS WARNING | 12 HOURS PRIOR

Public safety weather forecasts are such that a de-energization event will likely occur. This phase internal preparation and external coordination continue. Customer and public notifications continue at the prescribed cadence. ECC operations and coordination are maintained throughout the event.

Objectives

- Ensure life-safety
- Ensure employee welfare
- Continuous coordination and communication with affected customers

	Actions	Responsible	Complete
PSPS WARNING **12 HOURS PRIOR**	☐ Ensure staffing levels are appropriate for actions	Power Delivery DOC Chief	
	☐ Assign resources to appropriate circuits for de-energization and restoration	Power Delivery Field Incident Command	
	☐ Create generation mitigation plan (if needed)	Generation or Renewables DOC Chief	
	☐ Review switching orders based on known circumstances	System Operations	
	☐ Operational support ○ Coordinate with operations to support as needed	Vegetation Management	
	☐ Direct overall ECC operation ☐ Provide updates to EPG Director	ECC Executive	
	☐ Receive updates from the ECC Executive and provide guidance as needed (if activated	EPG Director/ CEO	
	☐ Update potential event in Foundry PSPS Operational Dashboard ☐ Any medical customers that could not be reached are turned over to local emergency services through the AFN Coordinator or EM Liaison Officer	ECC Manager	
	☐ Continuously update Emergency Management Agencies and ESF12 (Energy)	ECC Liaison Officer	
	☐ Continue compiling information for Post event report as appropriate	IM Specialist	
	☐ Update the event in PSP Portal as needed ☐ Coordinate messaging through the PSP Portal as needed	WIC	

PSPS WARNING **12 HOURS PRIOR**	☐ Continue updating PSPS website		
	☐ Enable 30 second data collection interval on PacifiCorp weather stations and alert capabilities ☐ Continuously monitor latest meteorological data ☐ Provide situational awareness briefings	Meteorology	
	☐ Continue outreach via official communications channels, media, and direct customer contact ☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage and social media ☐ Monitor the need for an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Local RBM assess CRC setup ☐ Notify and coordinate with key accounts ☐ Coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers ☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media ☐ Notify ECC Executive of medical/AFN customers who have not been reached with verified notification	Mission Control	
	☐ Coordinate with EM Liaison, RBMs, and service providers on AFN local resources ☐ Coordinate with mission control, Liaison Officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	

PSPS WARNING **12 HOURS PRIOR**	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with potentially impacted Tribes ☐ Coordinate with potentially impacted Tribes to address resource needs (with the RBM Coordinator)	Tribal Affairs Coordinator	

6.7 PSPS WARNING | 4-1 HOURS PRIOR

Public safety weather forecasts are such that a de-energization event will likely occur. This phase internal preparation and external coordination continue. Customer and public notifications continue at the prescribed cadence. ECC operations and coordination are maintained throughout the event.

Objectives

- Ensure life-safety
- Ensure employee welfare
- Continuous coordination and communication with affected customers

	Actions	Responsible	Complete
PSPS WARNING **4-1 HOURS PRIOR**	☐ Ensure all resources are staged appropriately	Power Delivery DOC Chief	
	☐ Review switching orders based on known circumstances	System Operations	
	☐ Operational support o Coordinate with operations to support as needed	Vegetation Management	
	☐ Direct overall ECC operation ☐ Final De-energization decision ☐ Provide updates to EPG Director	ECC Executive	
	☐ Receive updates from the ECC Executive and provide guidance as needed (if activated	EPG Director/ CEO	
	☐ Update event in Foundry PSPS Operational Dashboard	ECC Manager	
	☐ Notify local and state emergency management agencies including ESF-12 as appropriate ☐ Notify impacted Tribal emergency managers as appropriate	ECC Liaison Officer	
	☐ Continue compiling data into PUC post event reports	IM Specialist	
	☐ Update the event in PSP Portal as needed ☐ Coordinate messaging through the PSP Portal as needed ☐ Continue to update PSPS website	WIC	
	☐ Continuously monitor latest meteorological data ☐ Provide situational awareness briefings	Meteorology	
	☐ Continue outreach via official communications channels, media, and direct customer contact	JIT	

PSPS WARNING **4-1 HOURS PRIOR**	☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage and social media ☐ Monitor the need for an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls		
	☐ Staff CRC ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide direct and verified notification to medical and other AFN customers ☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media ☐ Notify customers of de-energization via all communications methods ☐ Initiate real-time social media updates	Mission Control	
	☐ Receive verification that all medical customers were contacted. In coordination with the liaison officer, if customers were not contacted initiate welfare check through local public safety partner, as appropriate. ☐ Coordinate with EM Liaison, RBMs, and service providers on AFN local resources ☐ Coordinate with mission control, RBM, liaison officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with potentially impacted Tribes ☐ Coordinate with potentially impacted Tribes to address resource needs (with RBM Coordinator)	Tribal Affairs Coordinator	

6.8 PSPS Event Cancellation

Public safety circumstances are such that PSPS actions are no longer necessary, make notifications the same as event end. This may occur prior to execution during watch or warning phases.			
Objectives • Ensure life-safety • Ensure employee welfare • Ensure compliance and documentation requirements			
	Actions	**Responsible**	**Complete**
PSPS EVENT CANCELLATION	☐ Provide final update to EPG Director/CEO	ECC Executive	
	☐ Manage demobilization of resources where appropriate	Power Delivery DOC Chief	
	☐ Update Foundry PSPS Operational Dashboard	ECC Manager	
	☐ Notify local and state emergency management agencies including ESF-12 as appropriate ☐ Notify impacted Tribal emergency managers as appropriate	ECC Liaison Officer	
	☐ Continue compiling data into PUC post event reports	IM Specialist	
	☐ Notify all appropriate partners of termination of response through PSP Portal. ☐ Update the event status in PSP Portal ☐ Continue to update PSPS Website	WIC	
	☐ Ensure winds are no longer expected to reach PSPS criteria and the threat has passed	Meteorology	
	☐ Continue outreach via official communications channels, media, and direct customer contact ☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage and social media ☐ Send an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Demobilize CRC for areas no longer impacted as appropriate	RBM Coordinator	

PSPS EVENT CANCELLATION	☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations		
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers ☐ Post notification on website and social media	Mission Control	
	☐ Coordinate with mission control, liaison officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Affairs	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with impacted Tribes ☐ Coordinate with impacted Tribes to address final needs (with the RBM Coordinator)	Tribal Affairs Coordinator	

6.9 PSPS Execution/De-Energization

Public safety circumstances are such that de-energization actions are in progress.			
Objectives • Ensure life-safety • Ensure employee welfare • Complete appropriate de-energization procedures • Continuous coordination and communication with affected customers			
	Actions	**Responsible**	**Complete**
PSPS EXECUTION **DE-ENERGIZATION**	☐ Mitigate generation as directed (if needed)	Generation or Renewables DOC Chief	
	☐ Execute switching orders ☐ Monitor local assets during event ☐ Provide guidance for any situation not directly covered in this plan	Region System Ops, Field Incident Command	
	☐ Monitor system stability	System Operations	
	☐ Ensure PSPS execution as directed	Power Delivery DOC Chief	
	☐ Direct overall ECC operation ☐ Provide updates to the EPG Director	ECC Executive	
	☐ Provide strategic guidance for any situation not covered within this plan	EPG Director/ CEO	
	☐ Operational support o Coordinate with operations to support as needed	Vegetation Management	
	☐ Update event in Foundry PSPS Operational Dashboard ☐ Coordinate response actions	ECC Manager	
	☐ Monitor partner Emergency Management agencies as needed	ECC Liaison Officer	
	☐ Continue compiling data into PUC post event reports	IM Specialist	
	☐ Update the event in PSP Portal as needed ☐ Coordinate messaging through the PSP Portal as needed ☐ Continue to update PSPS Website	WIC	
	☐ Provide continuous meteorological data and observations to ECC executive leadership	Meteorology	

PSPS EXECUTION **DE-ENERGIZATION**	☐ Monitor real time meteorological data to begin assisting with restoration planning		
	☐ Continue outreach via official communications channels, media, and direct customer contact ☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage and social media ☐ Monitor the need for an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Staff CRC ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers ☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media	Mission Control	
	☐ Coordinate with EM Liaison, RBMs, and service providers on AFN local resources ☐ Coordinate with mission control, liaison officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required ☐ Begin compiling data into PUC post event reports	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with impacted Tribes ☐ Coordinate with impacted tribes to address resource needs (with the RBM Coordinator)	Tribal Affairs Coordinator	

6.10 RESTORATION

Public safety circumstances are such that restoration actions have begun.			
Objectives • Ensure life-safety • Ensure employee welfare • Restore power • Ensure compliance and documentation requirements			
	Actions	**Responsible**	**Complete**
PSPS RESTORATION	☐ Identify order and priority of restoration	Power Delivery DOC Chief and ECC Executive	
	☐ Coordinate district patrol and restoration plan with field crews ☐ Make repairs to damaged infrastructure as discovered	Power Delivery Field Incident Command	
	☐ Coordinate restoration with field and engineering ☐ Patrol and restore in accordance with identified plan ☐ Complete restoration switching ☐ Record and photograph conditions found	System Operations, Power delivery DOC Field Crews	
	☐ Return generation to normal status (if needed)	Generation or Renewables DOC Chief	
	☐ Coordinate with operations to support as needed	Vegetation Management	
	☐ Direct overall ECC operation ☐ Terminate/demobilize de-energization response ☐ Provide updates to the EPG Director	ECC Executive	
	☐ Update the Foundry PSPS Operational Dashboard	ECC Manager	
	☐ Coordinate partner Emergency Management agencies needs	ECC Liaison Officer	
	☐ Continue compiling data into PUC post event reports	IM Specialist	
	☐ Notify Emergency Management agencies of restoration initiation and ETR through the PSP Portal ☐ Update the event status in PSP Portal ☐ Continue to update PSPS Website	WIC	
	☐ Confirm winds have decreased below critical thresholds and decrease in wind speeds is expected to continue	Meteorology	

PSPS RESTORATION	☐ Provide forecast for restoration process for field operations		
	☐ Continue outreach via official communications channels, media, and direct customer contact ☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage and social media ☐ Monitor the need for an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Staff CRC ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct, verified notification to medical and AFN customers ☐ Escalate unmet medical/AFN customer needs to ECC Executive ☐ Post notification on website and social media	Mission Control	
	☐ Coordinate with mission control, liaison officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required ☐ Continue compiling data into PUC post event reports	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with impacted Tribes ☐ Coordinate with impacted tribes to address any outstanding needs (with the RBM Coordinator)	Tribal Affairs Coordinator	
PSPS RESTORATION	☐ Update customers on ETR ☐ Direct and verified notification to medical/AFN customers	Mission Control	

6.11 PSPS Event End

All restoration is complete and event close out actions commence.			
Objectives			
• **Ensure compliance and documentation requirements** • **Complete ECC close out procedures**			
	Actions	**Responsible**	**Complete**
PSPS EVENT END **DE-ACTIVATION**	☐ Verify all restoration actions are complete and terminate response ☐ Deactivate the ECC ☐ Provide final update to EPG Director/CEO	ECC Executive	
	☐ Update Foundry PSPS Operational Dashboard ☐ Coordinate final documentation such as AAR, Regulatory reports, data collection, etc. ☐ Send participants after action survey and schedule After Action Review and conduct a Hotwash or After-Action meeting with internal business units having a role in the event	ECC Manager	
	☐ Conduct Hotwash or After-Action meeting with local and state emergency management agencies including ESF-12 ☐ Conduct Hotwash or After-Action meeting with impacted Tribes	ECC Liaison Officer	
	☐ Finalize compiling data into PUC post event reports ☐ Gather all notes and data for inclusion in AAR/IP	IM Specialist	
	☐ Notify all appropriate partners of ECC deactivation and termination of response through PSP Portal. ☐ Update the event status in PSP Portal ☐ Complete final PSPS Website update	WIC	
	☐ Ensure all data is collected in event log ☐ Correspond with Asset Management for the decommissioning of weather stations and the data is archived	Meteorology	

PSPS EVENT END **DE-ACTIVATION**	☐ Communicate with impacted Tribes ☐ Coordinate with impacted Tribes to address final needs (with the RBM Coordinator)	Tribal Affairs Coordinator	
	☐ Continue outreach via official communications channels, media,, and direct customer contact ☐ Continue coordination communication cadence and content ☐ Notification updates posted on homepage, social media, and PSPS webpage ☐ Send an updated press release or statement and respond to media inquiries ☐ Ensure official communications channels have consistent messaging ☐ Continue JIT coordination calls	JIT	
	☐ Demobilize CRC ☐ Notify and coordinate with key accounts ☐ Notify and coordinate with affected local and city government to address any resource needs, including Tribal Nations	RBM Coordinator	
	☐ Ensure adequate staffing throughout PSPS event to manage customer contacts via all channels ☐ Provide notice to customers (including critical priority customers) ☐ Provide direct and verified notification to medical and other AFN customers ☐ Post notification on website and social media	Mission Control	
	☐ Coordinate with mission control, liaison officer and local public safety partners to address unmet customer medical/AFN needs	AFN Coordinator	
	☐ Communicate with appropriate state regulatory agencies as required	Regulatory Coordinator	
	☐ Communicate with governor's office and appropriate state agencies and elected officials as required	Government Affairs Coordinator	
	☐ Communicate with impacted Tribes ☐ Coordinate with impacted Tribes to address final needs (with the RBM Coordinator)	Tribal Affairs Coordinator	

APPENDIX A: REFERENCES

- PacifiCorp Emergency Response Plan
- Annex 01-External Communication and Coordination
- PacifiCorp Community Resource Center Playbook
  - CRC Locations by County.xlsx
- PacifiCorp Critical Infrastructure Plan
- PacifiCorp Policy PAC-1000
- Mutual Assistance Agreements
  - BHE Intercompany Mutual Assistance Agreement
  - California Utility Emergency Association Mutual Assistance Agreement
  - Western Region Mutual Assistance Agreement
  - State Specific Mutual Assistance Agreements
  - "In Case of Crisis" Application for directory of other utility representatives
- Contact Lists
  - EM Partner POC Info.xlsx
- PSPS Website Process flow
  - PSPS_Process_v4.pdf
- Foundry PSPS References
  - PSPS Foundry Operational Dashboard overview.pdf
  - PSPS Foundry Dashboard User Guide 2025.pdf
  - Backup spreadsheet if Foundry is unavailable: PSPS De & Re Energization Timing .xlsx
- PSPS Cooperators calls
  - PSPS Cooperators Meeting Template.pptx
  - PSPS Cooperator Call Agenda.docx
- Reporting Templates (CA specific)
  - PSPS Data Reporting Template.xlsx
  - PacifiCorp PSPS Post Event Reporting TEMPLATE .docx
- Data collection during event
  - PSPS De & Re Energization Timing .xlsx
- CA Executive Briefing Template
  - PSPS_State_Executive_PacifiCorp.pptx
- Meteorology PSPS Checklist
  - Meteorology Team PSPS Operations Checklist

APPENDIX B: PSPS EVENT INITIAL INFORMATION TEMPLATE

	Notes/Comments:
System Operator provides to EM on initial call	
District(s)	
Substation(s)	
Circuit ID(s), including, if applicable, a specific description of any portion of a circuit which will be de-energized while other portions of the circuit remain energized	
Number of customers that will be impacted on each circuit	
ECC Decision Notes	
Date and time de-energization event will start	
Estimated duration of the event	
Date and time that affected customers will be notified under proposed notification plan	
Critical customers and facilities on the circuit such as hospitals, emergency centers, and water/water treatment plants that will be impacted	
With respect to each circuit or portion of a circuit planned for de-energization, a description of the applicable extreme fire weather conditions	
With respect to each circuit of portion of a circuit planned for de-energization, a description of the circumstances that give rise to the need to de-energize, such as “imminent and significant risk that strong winds will topple PacifiCorp power lines onto tinder-dry vegetation or will cause major vegetation related impacts on PacifiCorp facilities”	
A description of measures considered as an alternative to de-energization and why such measures alone are insufficient	
A description of the public safety benefit**s** the company hopes to achieve by de-energizing the applicable circuit(s)	
A description of proposed efforts to mitigate the adverse impacts on customers and communities impacted by de-energization	
The proposed date and time for notifying the appropriate PUC	

APPENDIX C: NOTIFICATION MATRIX

PRE-EVENT

Event Description: _____

Date of proposed event: _____

	Planned De-Energization		Estimated Restoration		Completed Restoration		Responsible Person / Position
	Date	Time	Date	Time	Date	Time	
a. Customer Notification							Mission Control
b. Emergency Responders							WIC, Emergency Manager or Local RBM
c. Local Government							Local RBM or Emergency Manager
d. Communications Providers							Emergency Manager or Local RBM
e. Critical Facilities							WIC, Emergency Manager or Local RBM
f. Regulatory Notifications							Regulation

POST EVENT

Customers previously notified of the event will receive notification that the event has ended. In addition, state specific notifications will take place in accordance with that state's specific requirements, see Appendix E.

APPENDIX D: PUBLIC COMMUNICATIONS PLAN

1. OVERVIEW

Weather conditions can change quickly. The PSPS communications plan is based on ideal conditions that permit advance notification. However, the public communications plan can adapt to changing conditions and shortened timelines.

PacifiCorp communications personnel will receive notification of a potential PSPS from Systems Operations up to seven days before an event is activated. Information provided will include the current or forecasted weather conditions and additional key variables triggering an event, the affected area, customer count, and the expected date and time of the event. This places the communications team at an awareness level.

The goal is for PacifiCorp customer care to begin notifying customers 48 hours in advance of a potential de-energization event. If this is not possible due to changing conditions, the notification process will begin as soon as possible. Issuing a public warning or watch prior to 48 hours is discouraged, because premature notification of an event that does not occur can lead to public fatigue.

2. PUBLIC SAFETY AUTHORITIES, LOCAL MUNICIPALITIES, EMERGENCY RESPONDERS

As outlined in Appendix C, the utility's Emergency Manager will notify the appropriate local agencies in the affected area, communicating the boundaries of impacted areas and expected duration. The WIC will coordinate PacifiCorp's PSP Portal notifications to registered public safety partners. PacifiCorp will work with agencies to minimize the impact of de-energization. Notifications will be documented for regulatory reporting purposes and submitted to the PUC after the event has ended.

3. PACIFICORP JOINT INFORMATION TEAM RESPONSIBILITIES

If a PSPS is planned, the JIT would manage public-facing communications for the event's duration.

Responsibilities:

- Determine, according to direction from the ECC Executive, any limits on information release.
- Develop accurate, accessible, and timely information for use in press/media briefings.
- Conduct media briefings in coordination with local PIOs.
    - A pre-determined location with conference rooms, abundant parking and space for news trucks and additional amenities should be identified for JIC. This location should ideally be separate from Emergency Operations Centers.
- Develop a schedule of media briefings based on the level of media interest and estimated duration of the event.
- Arrange for tours and other interviews or briefings that may be required.
- Monitor and forward media information that may be useful to incident planning.
- Maintain current information, summaries and/or displays on the incident.
- Participate in planning meetings.

4. PACIFICORP CUSTOMER CARE CENTER

Prior to, during and after an event, customers will be invited across a variety of communication channels to call the PacifiCorp customer care center for questions and concerns. Instructing customers to contact PacifiCorp for non-emergency, outage-related questions and concerns will be repeated across all applicable PacifiCorp public-facing communication channels, including in media advisories and interviews. Local 911

dispatch and emergency services will be encouraged to redirect customers to the PacifiCorp customer care center for non-emergency, outage-related questions, and concerns. Additional customer care staff will be activated as needed in a PSPS. The customer care number is 1-866-221-7070. Messages will be relayed in both English and Spanish.

5. **METHOD OF NOTIFICATION**

Affected customers will be contacted by text, email, or phone call based on their account preference. If no preference is selected, a phone call will be made to the primary phone number on the account. Event messages will be posted on social media, the company's website, and media advisories sent via FlashAlert.

6. **COMMUNICATION TIMELINE**

The following timelines may be modified if changing conditions do not allow for advance notification. In such cases, the company will notify customers as reasonably practicable.

Additional communication methods can be added or removed based on the circumstances of the event and regulatory requirements. In general, the company attempts to provide notices as follows:

72-48 Hours	De-energization Warning to Emergency Management Agencies
48-24 Hours	Initial Public De-Energization Warning
24 Hours	De-energization Warning
4-1 Hours	De-energization Imminent
Cancellation of Event (if appropriate)	PSPS Event Cancelled prior to de-energization notification
Event Begins	De-energization Begins
Re-energization Begins	Re-energization beginning notification to all within affected area
Re-energization Completed	Re-energization notification/confirmation to all within affected area
Event End	PSPS execution is complete and affected customers restored

72 Hours: PacifiCorp ECC is activated.

- Critical customer list is provided to the ECC Executive.
- PacifiCorp PIO begins drafting talking points for Regional Business Managers, the contact center agents, the customer advocacy team, and any other internal/external stakeholders per recommendation of ECC Executive. PacifiCorp's PSP Portal is updated to reflect event area(s) and updated messaging is coordinated to registered public safety partners and critical infrastructure.

48 Hours: Customer notification begins 48 hours prior to a forecasted event.

- PacifiCorp website updated to reflect potentially affected PSPS area.
- PacifiCorp's PSP Portal is updated to reflect event status and updated messaging is coordinated to registered public safety partners and critical infrastructure.
- The 48-hour alert script is launched, and customers are contacted by telephone, text, or email based on the customer's identified preference. All PacifiCorp social media platforms are updated with the alert.
- A media advisory is issued via FlashAlert.

24 Hours:

- The 24-hour alert script is used by the call center to launch outbound calls to all customers.
- Additional notification by text or email may also be sent to customers.
- PacifiCorp's PSP Portal is updated to reflect event status and updated messaging is coordinated to registered public safety partners and critical infrastructure.
- All PacifiCorp social media platforms are updated with the 24-hour alert.
- A media advisory is issued via FlashAlert.
- PacifiCorp identified medical needs or life support customers identified are personally contacted by call center agents.
    - All outbound calls will be tracked in order to provide the ECC Executive with a list of uncontacted customers.
    - A list of medical needs or life support customers not contacted is provided to the ECC Executive.
    - The number and location of uncontacted medical needs customers in the de-energization area will be provided to the AFN Coordinator who will coordinator with Liaison Officer and local public safety partners, as appropriate. Such coordination may lead to a wellness check.
- **Additional (as determined by regulatory requirement or event circumstance)**: Additional notification by text or email may also be sent to customers.
- All PacifiCorp social media platforms are updated with the one-hour imminent alert script.
- A media advisory is issued via FlashAlert.

Event Begins:

- The event begins script is used by the call center to launch outbound calls to all customers.
- Additional notification by text or email may also be sent to customers.
- Wellness check calls to customers with medical needs during extended events
- PacifiCorp's PSP Portal is updated to reflect event status and updated messaging is coordinated to registered public safety partners and critical infrastructure.
- All PacifiCorp social media platforms are updated with the event begins script.
- A media advisory is issued via FlashAlert.

Customer Contact during Re-energization

Re-energization Initiated:

- The re-energization-initiated script is used by the call center to launch outbound calls to all customers.
- Additional notification by text or email may also be sent to customers.
- All PacifiCorp social media platforms are updated with the re-energization-initiated script
- A media advisory is issued via FlashAlert.

Re-energization Completed:

- The re-energization completed script is used by the call center to launch outbound calls to all customers.
- Additional notification by text or email may also be sent to customers.
- Wellness check call for re-energized customers with medical needs

- All PacifiCorp social media platforms are updated with the re-energization completed script.
- A media advisory is issued via FlashAlert.

7. Medical Customer Outreach

Customers known within the Company database to rely on electricity for medical needs will receive additional outreach from the company requesting they evaluate the safety of their situation and consider a backup plan in case of a PSPS or any outage.

- Additional year-round communications will encourage customers dependent on electricity for medical needs to self-identify with PacifiCorp.
- PacifiCorp will work with local public safety and public health to identify additional opportunities to communicate with medical and other access and functional needs populations.

Outreach during a PSPS

24 hours prior to an event, additional phone calls will be made to known customers with access and functional needs and successful/unsuccessful contacts will be tracked.

- Additional outreach coordination with local emergency management and service providers for customers not contacted will take place before a PSPS.
- Frequency of calls will be determined by the estimated duration of the event. All calls will be tracked, and a spreadsheet of successful and unsuccessful calls will be shared with the ECC Executive. Unmet medical needs will be escalated to local public safety partners.

8. Phone and Email Script

"Hello this is PacifiCorp with an important safety message. We are actively monitoring hazardous weather conditions in [LOCATION] to mitigate wildfire risk. This [EVENT DAY] forecasted high winds, combined with current low humidity and dry conditions can result in flying debris coming in contact with power lines and escalating wildfire risk. We may issue a Public Safety Power Shutoff to prevent a potential fast-spreading wildfire from occurring.

Our crews continue to patrol power lines in the area and ahead of the [FORECASTED CONDITIONS] beginning [DAY AND TIME]. Currently, PacifiCorp is strategically positioning teams for on-the-ground real-time observation to monitor power lines and quickly respond to any issues.

Weather forecasts indicate a potential Public Safety Power Shutoff could be initiated [EVENT TIMEFRAME], should sustained winds and other measures exceed thresholds.

We will continue to monitor conditions and will provide updates should we need to issue a Public Safety Power Shutoff in your area.

For more information, please visit pacificpower.net or call our customer care team at 1-888-221-7070.

We appreciate your attention. Thank you.

Si necesita hablar con un representante que habla español, llame al 1-888-225-2611. "

9. Text Message Script

“We are monitoring for wildfire risk in your area. Updates to continue if a Public Safety Power Shutoff is issued [Day/Date].”

California Specific Information

The following excerpts are guidance from the California Office of Emergency Services PSPS Standard Operating Guide. California specific notification procedures are a requirement and must be followed per their guidance. For a comprehensive overview of all CalOES PSPS guidelines, reference the *PSPS Standard Operating Guide 2022*.

Section 3. Notification Process

3.1 State Executive and Operational Briefings

In addition to (public safety partner and customer) notifications, Utilities are responsible for sending appropriate invitations and facilitating State Executive Briefing calls with Cal OES, CAL FIRE, and the CPUC, as well as Operational Briefings with state and local public safety partners. These calls will address weather details, posture, and actions taken by Utilities, and the scope and impacts of the PSPS event. Cal OES has provided Utilities with template briefing slides on the Cal OES IOU PSPS Hub (https://psps-calema.hub.arcgis.com/) to foster standardized briefings. Calls will be held when a PSPS event is forecast to affect more than 100 customers. If the event is anticipated to affect 100 customers or less, the Utility will complete and distribute its PSPS briefing slides only.

State Executive Briefings will be held from the first day of the event if the Utility submits its first notification before noon. If the notification is received by Cal OES after 1200 hours, the first briefing will occur on the following day. State Executive briefings will continue daily until the final Event Concluded notification is received by Cal OES.

PacifiCorp will hold their State Executive Briefings at 1400 hours (2:00 PM) daily.

3.2.1 Notifications to Cal OES

Utilities have internal processes to activate their PSPS protocols. However, once any of the five stages are activated, they must notify the California State Warning Center (CSWC) via the PSPS State Notification Form. The Online PSPS State Notification Form on the Cal OES IOU PSPS Hub is the preferred method of official notification to Cal OES during PSPS events. However, if a Utility is unable to submit the online form, the PDF PSPS State Notification Form is available on the Cal OES IOU PSPS Hub as well. Additionally, Utilities must immediately call the CSWC at (916) 845-8911 once the first notification form of an event is submitted online or via email for confirmation of receipt. No additional calls to the Warning Center are required for subsequent submissions.

3.2.1.1 0700/1500 Daily Notifications

Once the initial notification has been submitted, ongoing notifications must be received by Cal OES at 0700 and 1500 hours (7:00 AM and 3:00 PM) daily through the duration of the event. Utilities may submit up to one

hour early of 0700 and 1500 hours. A notification submitted within this one-hour window will satisfy the 0700/1500 hours notification requirement. For instance, if a Utility has a major scope change and submits a notification at 0615 hours, it will qualify as both the stage change and 0700 hours notification. The Utility would not be required to submit again at 0700 hours.

3.2.1.2 Stage Change Notifications

When an IOU progresses to the next stage of a PSPS event, i.e., moves from Stage 1 to Stage 3 when it begins de-energizations, it will submit a notification to Cal OES in a timely manner. If a stage change notification is submitted between 0600-0700 hours or 1400-1500 hours, no additional notification is needed to satisfy the 0700/1500 notification requirement mentioned in the previous section.

3.2.1.3 Major Scope Change Notifications

Another trigger for notifications to Cal OES from IOUs is a major scope change. Major scope changes have been defined by each IOU and are provided below.

IOU	Definition of Major Scope Change
PacifiCorp	+/- 2,000 customers

When an IOU has a change in scope that meets their stated definition of major scope change during Stage 1 of a PSPS event, no additional notifications are required. Any major scope changes will be captured in the 0700/1500 notifications.

If a major scope change occurs during Stage 2, 3, or 4, an IOU will submit a notification promptly. During Stages 2, 3 and 4 of an event, if a major scope change notification is submitted between 0600-0700 hours or 1400-1500 hours, no additional notification is needed

3.2.1.4 Information Requirements

In advance of a Utility's actual de-energization, each Utility must provide the CSWC with real-time data of potentially impacted areas. As the PSPS event unfolds, Cal OES requires continuous real-time information for effective response operations.

Cal OES uses ESRI's Geographic Information System (GIS) tools for gathering, managing, and analyzing PSPS data provided by Utilities. The following tools are used:

ArcGIS Pro (shapefile, Geodatabase (gdb))
ArcGIS Online (AGOL web services)

Cal OES needs the following geospatial information for response operations:

Outage areas
Circuits
Impacted critical customers

If available, the Utility provides the CSWC with access information to their data portal or AGOL web services upon receipt of the Notification Form.

The data portal or AGOL web service information is coordinated through the Cal OES Data and Geospatial Unit. The Utility must notify the Cal OES Data and Geospatial Unit staff of any changes in the GIS data delivery method. The Utility is responsible for its spatial data updates and tracking. ESRI AGOL web services, data portal, or GIS datasets and include circuit-level information on:

- Medical baseline and life support customer count
- Circuit status
- Monitoring
- De-energized
- Re-energized
- Period of concern
- County
- Circuit name
- Critical facilities and infrastructure, if available
- Total customers

If a Utility cannot provide ESRI AGOL web services, data portal access, or GIS data sets, the Utility must provide real-time continuous updates in PDF forms and PDF maps.

Section 5: Battle Rhythm – PSPS Operational Activity Matrix

The Operational Activity Matrix provides a time-phased list of actions in response to a PSPS event in California. Depending on the duration or intensity of the event, some actions may continue throughout subsequent phases of response.

The below actions are in addition to the PacifiCorp PSPS Checklist items

Time	Action
Ongoing through event	☐ Submit *Online PSPS State Notification Form* or the *PDF* version to the CSWC at 0700 and 1500 hours (refer to 3.2.1.1 & 3.2.1.2) ☐ Facilitates State Executive Briefings and local Operational Briefings – PacifiCorp scheduled for 1400
72 hours prior to weather event	☐ Simultaneously notifies the CPUC via email and the CSWC via the Online PSPS State Notification *Form* or the *PDF* version
48 hours prior to weather event	☐ Initiates request for CRC assets (CRC required in California)

Weather event starts/de-energization	☐ Sends notification of Decision to De-energize to CSWC via *Online PSPS State Notification Form* or the *PDF version* and CPUC via email ☐ Sends notification of De-energization Initiated to CSWC via *Online PSPS State Notification Form* or the *PDF version* and CPUC via email
Re-energization initiated	☐ Sends notification of re-energization initiated to CSWC via Online PSPS State Notification Form or the PDF version and CPUC via email
Event concluded	☐ Sends Event Concluded notification to CSWC via *Online PSPS State Notification Form* or the *PDF* version and CPUC via email once all lines have been restored. ☐ If no lines de-energized, notification is submitted once period of concern has passed ☐ Begins to prepare PSPS Post Event Report for CPUC

CALOES PSPS STANDARD OPERATING GUIDE 2022-05-17.PDF

Idaho Specific Information

In response to the outages, emergencies, and cyber security incidents throughout the State we have developed expectations for communication and notification procedures between the Utility Companies and the Idaho Public Utilities Commission

Curtailment (PSPS)

- Stakeholders: Notification process/ plan for large customers that provide service to other customers.
    - Information Shared: Engage stakeholders in changes to curtailment plans that could directly affect their operations and provide timely notification of curtailment.
    - **IPUC – Groups that should receive curtailment information at the PUC are:**
        - IPUC Secretary – secretary@puc.idaho.gov
        - IPUC Outage Group – Outage.Alert@puc.idaho.gov
        - ESF 12 Group – ESF12.Alert@puc.idaho.gov
            - ESF-12 Phone: 208-501-4088
            - Information Shared – Situational report (Start date/time, Location, duration, customer count, cause, contact, and when restored the date/time with updates)

Wyoming Specific Information

Service interruptions that meet the criteria for reportable service interruptions events, shall be reported to the Commission within two (2) hours of determination of the interruption reporting threshold. Major service interruptions, minor service interruptions and major events are outlined below. *Reference the RMP Service Interruption and Reporting Plan for more information.*

1. Reportable Service Interruption Events:

    1. Minor Service Interruption: Any real-time, unplanned and planned electrical service interruption that involves five hundred (500) or more network congruent customers for two (2) hours or more.

2. Major Service Interruption:

    (a) Any real-time, electrical service interruption which affects twenty-five (25) network congruent distribution customers or more for eight (8) hours or more.

    (b) Any real-time, unplanned electrical service interruption where a transmission or distribution substation breaker opens and results in a sustained interruption to distribution customers.

    (c) Any electrical service interruption for which the Company can reasonably be expected to recognize that the outage could produce significant detrimental effects to customers, facilities or public safety.

3. In the event of a planned service interruptions, guidelines for reporting include:

    1. The Commission also requires notification for all planned major service interruptions at least 48 hours in advance except in emergencies.

    2. Notification to customers will occur at least 2 business days in advance of a planned service interruption.

Rocky Mountain Power | Pacific Power

Annex 01:
Public Safety Power Shutoff
Community Resource Center Playbook

Document Owner: The PacifiCorp emergency management team is responsible for maintaining this document. This includes scheduling annual reviews and exercises, updating content based on annual reviews and exercises, and redistributing the new version to document stakeholders.

Document Disclaimer: This playbook is specific to Public Safety Power Shutoff scenarios. The measures and planning detailed in this plan do not alter the utility's approach and communication around non-Public Safety Power Shutoff outages.

This document should be considered iterative. The area-specific Public Safety Power Shutoff plan will be modified as necessary.

Author: PacifiCorp emergency management

Version: 4.0

Origination Date: September 2021

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1. Record of Revisions

Change #	Date of change	Document Section	Change Summary	Responsible
2022-01	07/22/2022	1.1.16	New CRC locations	Emergency Management
2022-02	06/27/2023	1.1.17	Contact Info Update	Emergency Management
2024-01	03/11/2024	All	Terminology alignment, contact information updates	Emergency Management
2025-01	03/15/2025	All	Re-titled to match naming convention Re-ordered sections and renumbered. Updated with new process and technology information	Emergency Management

2. Acronyms

Acronym	Term
ADA	American with Disabilities Act
AFN	Access and Functional Needs
CRC	Community Resource Centers
ECC	Emergency Coordination Center
EMT	Emergency Medical Technician
EV	Electric Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
PSPS	Public Safety Power Shutoff
PUC	Public Utility Commission
RBM	Regional Business Manager
SOP	Standard Operating Procedures

3. Plan Fundamentals

3.1 Purpose

This playbook provides guidelines on how PacifiCorp will activate, staff and provide resources for Community Resource Centers (CRC) that can be activated across our service territory during Public Safety Power Shutoffs (PSPS). PacifiCorp understands that Community Resource Centers are not just a requirement but an integral part in ensuring community members affected by PSPS have access to basic resources and up-to-date information.

3.2 Scope

This playbook is activated in tandem with the PSPS Execution Playbook. Included within is guidance on providing customers a safe location to meet their basic power needs during PSPS. The playbook includes general information on CRC site selection, activation, operations, resources, and communications. Since each PSPS presents unique challenges and needs, the CRC model is intended to be flexible and able to adapt to meet the needs of each event and community.

3.3 Objectives

1. Provide a safe universally accessible location to meet basic power needs.
2. Provide strong leadership and effective management.
3. Ensure a quick response to a PSPS event that requires CRC activation.
4. Develop standard operating procedures (SOPs) and checklists for CRC activations and operations.
5. Partner with local, state, and federal agencies and appropriate private sector organizations.
6. Develop and maintain mutual aid agreements with local and tribal agencies, non-governmental organizations, and others, as needed.
7. Develop and implement an effective communications process for internal and external stakeholders.
8. Periodically, exercise the plan to ensure its effectiveness and change as needed.

3.4 Situation Overview

With wildfires becoming more frequent and intense throughout our region, protecting the communities that PacifiCorp serves while providing safe, reliable power is the utility's highest priority. PacifiCorp may de-energize power lines as a preventative measure during periods of the greatest wildfire risk. Using historical weather data accompanied by fuels data, PacifiCorp has identified several Fire High Consequence Areas within its service territory that have an elevated risk of rapid wildfire growth within or near populated areas. A comprehensive overview of Public Safety Power Shutoffs is available in the PacifiCorp Public Safety Power Shutoff Execution Playbook.

Community Resource Centers are activated when a PSPS is occurring to serve the community in the de-energization area. PacifiCorp works with local emergency managers, public safety partners, and tribal leadership to identify appropriate deployment locations for CRCs. Additionally, PacifiCorp contracts with private vendors to support the deployment of temporary CRCs in the event that fixed facilities are not a feasible option.

3.5 Plan Review Schedule

Complete By:	Activities to be performed
April of current year (pre-fire season)	• Ensure contracts are in place • Update contacts • Complete plan updates
December of current year (post-fire season)	• Update feedback section • Identify areas of improvement • Identify additional changes as required by PUCs

4. Community Resource Centers

PacifiCorp utilizes a contracted vendor for logistical support in deploying Community Resource Centers should the need arise during a Public Safety Power Shutoff. Community Resource Centers will be activated once a PSPS de-energization is imminent. The center(s) will generally be open daily from 8:00 AM to 10:00 PM with the ability to adjust based on the community's need and conditions. PacifiCorp will utilize brick and mortar facilities for CRC locations unless a facility is not available or feasible in which case logistics support can deploy a Community Resource Center tent which is 33ft x 18ft and able to sustain winds of 55mph gusting to 65mph. PacifiCorp personnel will staff the center(s) to assist and provide information to community members

4.1 Establishing a CRC

All CRC locations will be coordinated with local emergency managers. CRC locations are then vetted using a checklist that was developed with guidance from Public Utilities Commissions and the current Americans with Disabilities Act (ADA) Checklist for Emergency Shelters to ensure services are equitable and accessible for populations with medical and other access and functional needs.

PacifiCorp emergency management meets regularly with local and regional access and functional needs service providers, local emergency managers, and Tribal partners. Upon identification of a location, emergency management will coordinate with the local partners to ensure the site location and support services are universally accessible for the impacted community. PacifiCorp Regional Business Managers (RBM) are responsible for staffing CRCs.

Please refer to Table 1 of *PacifiCorp_2025_PSPS_Pre-SeasonReport_Tables_Redacted.xls* for a list of identified CRC locations.

4.2 Activating a CRC

See Attachment 1: CRC Activation Checklist

4.3 Public Health

Air quality monitors will be utilized at CRCs that are impacted by wildfire smoke. The logistics vendor will provide air purifiers at the CRC to keep air quality levels at acceptable levels as identified by the local public health officials. Any additional resources or procedures needed to comply with local health guidance will be sourced and provided at CRCs such as masks, gloves, hand sanitizer, and social distancing practices

4.4 Logistics Vendors

PacifiCorp has signed master service agreements with two logistics vendors (primary & alternate) that will deploy, setup, and maintain CRC locations upon request.

- Primary: Fire DAWG Green, Inc.
- Alternate: Abel Fire Equipment

4.5 CRC Resources

Community Resource Centers will provide the following general services and resources while operational:

• Parking signage and traffic safety equipment • Shelter from environment • Heating and cooling capabilities • Air purifiers & air quality monitors • Potable water & non-perishable snacks • Seating and tables • Restroom facilities • Refrigeration & heating for medicine and baby needs • Interior and area lighting • Televisions • Games and entertainment activities	• Ice • On-site security • Communications capability such as Wi-fi, radio, cellular phone etc. • On-site medical support (EMT-A at a minimum, Paramedic preferred) • Charging stations for cell phones, medical devices, radios, computers, etc. • Small crates for pets • AFN/LEP population support • Personal Protective Equipment • Portable ADA ramp

Please refer to Table 2 of *PacifiCorp_2025_PSPS_Pre-SeasonReport_Tables_Redacted.xls* for any stakeholder recommendations on AFN needs at PacifiCorp CRCs.

4.6 Generic Site Footprint & Needs

The basic facility needs of a Community Resource Center location include:

- Adequate parking
    - Handicap Parking
    - Space for public parking
    - Space for vendor equipment
- A minimum of 600 sq. ft. and the capacity to host a minimum of 40 people.
- ADA compliant entryways
- Ground level access
- A separate room for nursing
- A large room for seating/gathering
    - Area or separate room for eating
- Indoor restrooms or room outdoors for portable toilets

Optimal site features:

- Backup Power Generator or direct generator connections to building power
- Additional office space for PacifiCorp Staff
- HVAC system with recommended filtration and circulation capabilities to handle wildfire smoke.

- A kitchen with microwave or stove
- Electric Vehicle Charging Stations

5. CRC Activation Timeline

Timing	Action	Responsible Department
~72 hrs	Emergency Coordination Center activation	Emergency Management
~48 hrs	Decide likelihood of CRC needed, possible thresholds: • Outage Overnight • Outage > 8 hours • Customer impacts requiring extra support • Other ongoing public safety incidents	• ECC Executive • Emergency Management
~44 hrs	Contact logistics vendor of the potential for a CRC activation to allow them to begin acquiring resources.	Emergency Management

~44 hrs	Coordinate with the local emergency management to identify CRC location & public health guidelines
	• Identify if the CRC will be co-located with a locally operated emergency shelter
	• Identify current public health guidance
	  o Pandemic/Outbreak information
	  o Air quality thresholds
	• Submit specifics to the vendor and ask them to create a site plan
		• Emergency Management
		• CRC Logistics Vendor

~30 hrs	Contact and survey CRC location to confirm site setup • Not in use for other purposes • Any other concern • Purchase potable water and nonperishable snacks	RBM
~26 hrs	• Initiate movement of CRC logistic vendor resources • Initiate movement of EV Charging Trailers	Emergency Management
~4 hrs	Dispatch company representatives to CRC as needed	Emergency Management
~2 hrs	• Ensure set-up of CRC and completeness of resources on-site • Add CRC location and info to webpage/social media	• Regional Business Managers • Corporate Communications
Event	CRC Operational • Announce that CRC is open on website/social media • Keep information on PSPS & CRC status updated • Regional Business Managers maintain sufficient staffing during operational hours	• CRC logistics vendor • RBM • Emergency Management • Corporate Communications
Post Event	Decision to de-mobilize CRC	ECC Executive
Post Event	Coordinate administrative and financial obligations to CRC logistic vendor	Emergency Management

6. CRC Communications Overview

6.1 Overview

PacifiCorp has a strategic Public Communications Plan for Public Safety Power Shutoffs that includes messaging for Community Resource Centers. A comprehensive overview of our Public Communications Plan for PSPS events can be found in our PSPS Execution Playbook.

6.2 Communication Timeline

The following timelines may be reduced if changing conditions do not allow for advance notification to customers. In these cases, the company will notify customers as soon as possible and communicate specific event information. The communication timeline is outlined in the PSPS Execution Playbook.

Additional communication methods can be added or removed based on the circumstances of the event but in general all communications on PSPS events will be sent via phone, text, email, and posted to our webpage and social media accounts.

7. CRC Feedback & After-Action Review

7.1 Review and Improvement Plans

PacifiCorp emergency management will review all feedback from customers, logistics staff, Public Utilities Commissions, and PacifiCorp employees to compile an after-action review and improvement plan. PacifiCorp emergency management will use the following tools for collecting feedback:

- Attachment 2: Customer Feedback Forms will be available to customers during and after a CRC activation. Printed feedback forms will be provided onsite, or feedback can be collected as listed below:
    - Pacific Power website www.pacificpower.net/ or by contacting customer service at: 888-221-7070.
    - Rocky Mountain Power website www.rockymountainpower.net or by contacting customer service at: 888-221-7070
- After action meeting with impacted public safety partners Attachment 3: CRC Usage, Results, Feedback, & Challenges will hold an ongoing list of metrics and feedback

Attachment 1: CRC Activation Checklist

Complete	Timeline	Action	Responsible Department
☐	72-48 hrs	Receive approval from ECC Executive to establish a CRC	Emergency Management
☐	48 hrs	Contact CRC logistics vendor of the potential for a CRC activation to allow them to begin acquiring resources	Emergency Management

☐	48 hrs	Coordinate with impacted county to identify CRC location and public health guidelines.
		• Identify if the location will also be used for an emergency shelter if an incident were to occur
		  o Consider establishing joint operations plan where Pacific Power operates location during designated hours and county operates location after hours.
		• Identify current public health guidance
		  o Pandemic/Outbreak information
		  o Air quality thresholds
		• Pass information onto vendor for site safety
			Emergency Management

☐	40 hrs	Contact & Survey CRC location to confirm site setup • Ensure enough generation capacity is requested for the site • Not in use for other purposes • Accessible for population with access & functional needs • Any other concerns	RBM
☐	24 hrs	Initiate movement of CRC logistics vendor resources Add CRC location and info to webpage/social media	Emergency Management
☐	4 hrs	Dispatch company representatives to CRC as needed	Emergency Management
☐	2 hrs	• Ensure set-up of CRC and completeness of resources on-site • Add CRC location and info to webpage/social media • Update 2-1-1 on CRC location, hours, and resources	• RBM • Corporate Communications
☐	8am-10pm Daily during PSPS	CRC Operational • Announce that CRC is open on website/social media • Keep information on PSPS & CRC status updated • RBMs maintain sufficient staffing during operational hours	• Logistics Contractor • RBM • Emergency Management • Corporate Communications
☐	Post PSPS Event	Decision to de-mobilize CRC	ECC Executive
☐	1 week after PSPS	Coordinate administrative and financial obligations to CRC vendor	Emergency Management

Attachment 2: Customer Feedback Form

1. **OPTIONAL** What is your home address? _____

2. What is your zip code: _____

3. How were you notified of the Community Resource Center?
   ☐Phone call ☐Text ☐Email ☐Social Media ☐TV News ☐Radio News
   ☐Other_____

4. Was the CRC easily accessible? ☐ Yes ☐ No

If you answered No, please explain why:

5. Were you able to keep your essential/medical devices charged and functioning? ☐ Yes ☐No

If you answered No, please explain why:

6. Did you have any needs that staff at the CRC did not meet? ☐ Yes ☐ No

If you answered Yes, please explain why:

7. Additional comments:

Attachment 3: CRC Usage Results, Feedback, and Challenges

Usage results, feedback, and challenges from any PSPS event CRC activation will be listed here.

Please refer to the *PacifiCorp_2025_PSPS_Pre-SeasonReport_Tables_Redacted.xls* for the following tables:

- Table 3 – Prior Year PSPS CRC Usage Metrics
- Table 4 – Prior Year CRC Customer Feedback
- Table 5 – Prior Year IOU CRC Challenges

Appendix F
Attachment 21

PACIFICORP

Rocky Mountain Power | Pacific Power

EMERGENCY RESPONSE PLAN

Document Owner: PacifiCorp Emergency Management is responsible for the maintenance of this document. This includes scheduling reviews and exercises, updating content, and distributing updated versions to applicable stakeholders. These activities will be incorporated - into the Emergency Management Integrated Preparedness Plan (IPP) and approved by PacifiCorp Executive Leadership.

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Author: PacifiCorp Emergency Management
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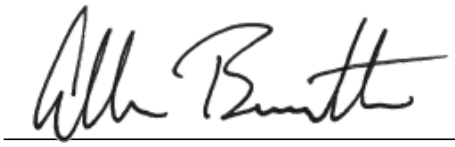
1. INTRODUCTION

1.1 Authorization

This PacifiCorp Emergency Response Plan (ERP) is in alignment with the Berkshire Hathaway Energy Incident Management Program Standards and the Berkshire Hathaway Energy Emergency Coordination Guide. To ensure accuracy and that the plan remains relevant and actionable, emergency management coordinated with internal business units on the plan update in 2025. Feedback from a series of meetings with external stakeholders also informs the current ERP. The ERP consists of a basic plan, an annex, related attachments, and additional support information.

This plan is authorized under the authority of the PacifiCorp Vice President of Transmission and Distribution Operations.



Allen Berreth

PacifiCorp Vice President T&D Operations

April 23, 2025

1.2 Privacy Statement

Portions of this plan contain information that raises personal privacy, trade secret, or security concerns. Those portions may be exempt from mandatory disclosure under the Freedom of Information Act (see 5 United States Code §552, 41 Code of Federal Regulations Part 105-60). It is to be controlled, stored, handled, transmitted, distributed, and disposed of in accordance with the Critical Infrastructure Information Act of 2002 and is not to be released to the public or other personnel who do not have a valid "need to know" without prior approval of the issuing agency.

In addition, the disclosure of information in this plan could compromise the security of essential equipment, services, and systems of PacifiCorp or otherwise impair its ability to carry out essential functions. Distribution of the plan in whole or in part is limited to those personnel who need to know the information to successfully implement the plan.

PacifiCorp distributes copies of the Emergency Response Plan as required to regulatory agencies and as necessary to promote information sharing and facilitate a coordinated interagency continuity effort.

1.3 Record of Changes

Date Reviewed	Activity	Summary of Changes	Approvers
June 2019	Plan implemented		Jeff Bolton
October 2019	Plan reviewed and revised		Jeff Bolton
October 2020	Plan reviewed and revised		Jeff Bolton
October 2021	Plan reviewed and revised		Jeff Bolton
July 2022	Plan reviewed and revised		Jeff Bolton Jona Whitesides Tyler Averyt
August 2022	Plan reviewed and revised	Section 1. Mitigation Overview and Operational Mitigation Section 4. Control and Coordination Acronyms table added Section 5. Control and Coordination	Jeff Bolton Jona Whitesides Horace Ward Nora Yotsov Erik Brookhouse
September 2022	Plan reviewed and revised	Title page. Formatting and copyright notice Record of Revisions: addition of reviewers and approvers of plan Section 1. Company Overview Section 2. Purpose Section 3. Situation Section 6. Mutual Assistance Agreements Section 8. Sheltering, Evacuation and Accountability	Curt Mansfield Jona Whitesides
April 2023	Plan reviewed		All stakeholders
January 2024	Plan reviewed and revised	Re-organized content to align with industry best practices and BHE incident management plan standards Updated formatting to adhere to BHE standards Updated incident management organizational structure	Corporate Communications Customer Service Emergency Management Executive leadership Government Affairs Regulatory

		Updated governance due to reorganization of executive leadership Deleted Operational Leadership Branch Merged elements of previous Annexes into the Emergency Response Plan • Governance Transfer • Executive Policy Group • Emergency Coordination Center • Department Operations Center • On Scene Incident Response • Resourcing and Mutual Assistance • Training and Exercises • Internal Emergency Communications • Outage Restoration Procedures Updated and reorganized Annex 09 External Communications; renamed as Annex 01 External Emergency Coordination and Communication Added sections • Objectives • Threat Overview • Safety	Safety System Operations External partners
April 2025	Plan reviewed and revised	Reviewed plan with stakeholders listed to incorporate any updates Updated incident management organizational structure Added new incident management positions and descriptions Added sections: • Assumptions	Corporate Communications Emergency Management Executive Leadership Government Affairs Regulatory Affairs

		• Limitations • Other Planning Considerations	Safety System Operations External Partners

1.4 PacifiCorp Acronyms

Acronym	Term
CEII	Contains Critical Energy Infrastructure Information
CEO	Chief Executive Officer
CUEA	California Utility Emergency Association
DOC	Department Operations Center
ECC	Emergency Coordination Center
EOP	Emergency Operations Plan
EPG	Executive Policy Group
ERP	Emergency Response Plan
FEMA	Federal Emergency Management Agency
FERMs	Fire and Emergency Response Managers
FERC	Federal Energy Regulatory Commission
FOIA	Freedom of Information Act
GETS	Government Emergency Telecommunications Service
HF	High Frequency
GSOC	Global Security Operations Center
HSEEP	Homeland Security Exercise Evaluation Program
ICS	Incident Command System
IM	Incident Management
IPP	Integrated Preparedness Plan
MS	Microsoft
NERC	North American Electric Reliability Corporation
NIMS	National Incident Management System
PACE	Primary, Alternate, Contingency, and Emergency
PACE	PacifiCorp East (Rocky Mountain Power)
PACW	PacifiCorp West (Pacific Power)
PCC	Portland Control Center
PP	Pacific Power
PUC	Public Utility Commission
RBM	Regional Business Manager
RMAG	Region Mutual Assistance Group
RMP	Rocky Mountain Power
SHARES	Shared Resources
WECC	Western Electricity Coordinating Council
WIC	Wildfire Intelligence Center
WPS	Wireless Priority Service
WRMAA	Western Region Mutual Assistance Agreement
WRMAG	Western Region Mutual Assistance Group

2. BASE PLAN OVERVIEW

2.1 Purpose

The purpose of the Company Emergency Response Plan (ERP) is to assist PacifiCorp (Pacific Power & Rocky Mountain Power) personnel to support a safe, efficient, and coordinated response to emergencies and disasters which may impact the delivery of electric service. The ERP is the primary reference material for an emergency response affecting PacificCorp's employees, assets, or business continuity.

The ERP includes a base plan, Annex 01 External Emergency Coordination and Communication, and other support materials. Together these provide policies and procedures used in response to any emergency incident or planned event which could affect PacifiCorp personnel and assets and exceeds day to day operational capabilities.

2.2 Scope

The ERP defines PacifiCorp's all-hazards approach to incident response. An all-hazards approach is a comprehensive emergency management framework that considers the full range of emergencies or disasters the business may face. This approach encourages an effective and consistent response to incidents of all scales, small to catastrophic, regardless of the cause.

This plan does not replace day-to-day operational or internal business unit continuity plans.

2.3 Objectives

The objectives of the ERP are to:

- Establish a flexible and dynamic central command-and-control function for incidents and events requiring control and support beyond the capabilities of PacifiCorp's day-to-day tactical response resources.
- Base the PacifiCorp response framework on the principles of the National Incident Management System (NIMS).
- Provide guidance and support to emergency responses of any size or scope throughout the company.
- Utilize the emergency management program and plans throughout PacifiCorp.
- Creates the framework for staff training on the roles, responsibilities, and processes of the ERP.
- Improve PacifiCorp's response and future emergency response plans through capturing strengths and areas for improvement from activations, exercise, and industry best practices.

2.4 Assumptions

The following assumptions include expected effects from an emergency or disaster which may impact personnel and assets and exceed day to day operational capabilities:

- When a power outage occurs, it may have a widespread community impact and PacifiCorp is committed to restoring power as quickly as possible.
- In the event of an emergency or disaster, company assets and facilities may be impacted.
- In the event of mass telecommunication failure, PacifiCorp must exercise alternative means of communication, such as radio communication between all units within an incident response structure that are supporting the incident.
- Some personnel may be impacted by an incident, including being under evacuation orders**.** Employees will ensure the safety of their families first.
- An emergency or disaster may inhibit the ability for employees to report to work in person.

2.5 Limitations

Limitations consist of actions either required (must do) or prohibited (cannot do) in emergency response operations. The following constraints and restraints were identified:

- Applicable by state, regulatory stipulations will be fulfilled as required.
- PacifiCorp upholds its commitment to the safety of its employees, facilities, and assets.
- PacifiCorp will maintain accurate, up-to-date incident information as required.

2.6 Other Planning Considerations

The following matters must be considered when developing and updating the ERP:

- Incidents may happen concurrently and require coordinated response efforts. PacifiCorp's incident management framework provides a standardized response structure that can be scaled and adapted to meet the needs of each incident.
- PacifiCorp employees will fulfill emergency responsibilities as needed based on the scale of the incident.
- PacifiCorp uses an all-hazard approach to incident response. This considers and continually assesses an expansive list of human-caused, natural, and technological threats that could affect company assets across the company's service territory.
- Mutual assistance may be utilized when resources are not adequate for response.

2.7 Plan Alignment

Within PacifiCorp there are specific roles and responsibilities during an emergency event that are guided by department and business unit-specific policies and procedures. The ERP acknowledges that the actions that occur pursuant to this plan are interdependent and referenced in other department and business unit specific policies, procedures, and emergency provisions.

Examples of areas where interdependencies exist include, but are not limited to:

- PacifiCorp Business Continuity
- PacifiCorp Communications
- PacifiCorp Power Delivery including Pacific Power and Rocky Mountain Power Operations
- PacifiCorp System Operations including Main Grid and Region System Operations
- PacifiCorp Customer Experience including Customer Care Centers and Commercial Accounts and Community Relations
- PacifiCorp Metering Business Systems Support
- Pacific Power and Rocky Mountain Power corporate functions: Finance, Human Resources, Procurement, and Information Technology
- PacifiCorp Corporate Communications

Primary and supporting documents incorporated, cited, or referenced herein include:

- PacifiCorp Executive Emergency Manual
- PacifiCorp Joint Information Team Response Guidelines
- PacifiCorp Integrated Improvement Plan
- PacifiCorp State Wildfire Mitigation Plans
- PacifiCorp Energy Supply Emergency Procedures
- Pacific Power and Rocky Mountain Power Energy Emergency Curtailment Plans
- PacifiCorp Grid Operations – Business Recovery Plan
- PacifiCorp System Operations – Emergency Operating Plan
- Mutual Assistance Agreements
- Transmission Grid Operations Operating Procedures:
    - Transmission Grid Operating Procedures - PCC-107 - Generation Alerts
    - Transmission Grid Operating Procedures - PCC-108 - Capacity and Energy Emergency Procedure for PACE and PACW
- Transmission Grid Operating Procedure - PCC-600 - Grid Operations Emergency & Trouble Notification Guidelines
- Transmission Grid Operating Procedures - PCC-605 - Issuing Directive and Communicating Effectively
- Company standard EA021
- Company Standard TA021
- Berkshire Hathaway Energy Exercise Standards
- Berkshire Hathaway Energy Emergency Coordination Guide
- Berkshire Hathaway Energy Incident Management Program Standards

- California PUC General Order 95
- California PUC General Order 165
- California Public Resource Code 4292
- California Public Resource Code 4293
- National Electric Safety Code
- United States Department of Homeland Security, Federal Emergency Management Agency (FEMA) – National Incident Management System (NIMS)

North American Electric Reliability Corporation (NERC) Standards:

- United States Presidential Policy Directive 21: Critical Infrastructure Security and Resilience
- United State Department of Energy Office of Cyber Security, Energy Security and Emergency Response State Energy Security Plan Option Drop In: Cross-Sector Interdependency Diagrams
- NERC Standard - EOP-001-2 - Emergency Operations Planning
- NERC Standard - EOP-003-2 - Load Shedding Plans

2.8 Company Overview

PacifiCorp is the largest grid operator in the western United States, serving 2 million customers in six western states. Part of Berkshire Hathaway Energy (BHE), the company is comprised of two divisions:

- Rocky Mountain Power
  - Based in Salt Lake City, Utah
  - Serves customers in Utah, Wyoming, and Idaho
- Pacific Power
  - Based in Portland, Oregon
  - Serves customers in Oregon, Washington, and California.

PACIFICORP

SERVICE AREA	141,500 square miles
ELECTRIC CUSTOMERS SERVED	2.1 million
NET-OWNED GENERATION CAPACITY	10,833 megawatts
OWNED RENEWABLE AND NONCARBON CAPACITY	3,299 megawatts

PacifiCorp owns and operates more than 18,200 miles of transmission lines across 10 western states.

The Company owns and operates a diverse portfolio of generation resources, including 73 generation facilities in eight states that generate electricity from the following sources:

- coal
- natural gas
- hydroelectric
- solar
- geothermal
- largest wind fleet by a regulated utility in the western U.S.

PacifiCorp also owns and manages 46,000 acres of land reserved for wildlife habitat, forestry, and recreation.

2.9 Threat Overview

2.9.1 Hazards

PacifiCorp's all-hazards approach considers the wide range of human-caused, natural, and technological threats that could affect a facility or operational structure within the company's service territory. The types of threats, likelihoods of occurrence and projected impacts vary across the service territory. PacifiCorp's incident management framework provides a standardized response structure that can be scaled and adapted to meet the needs of each incident.

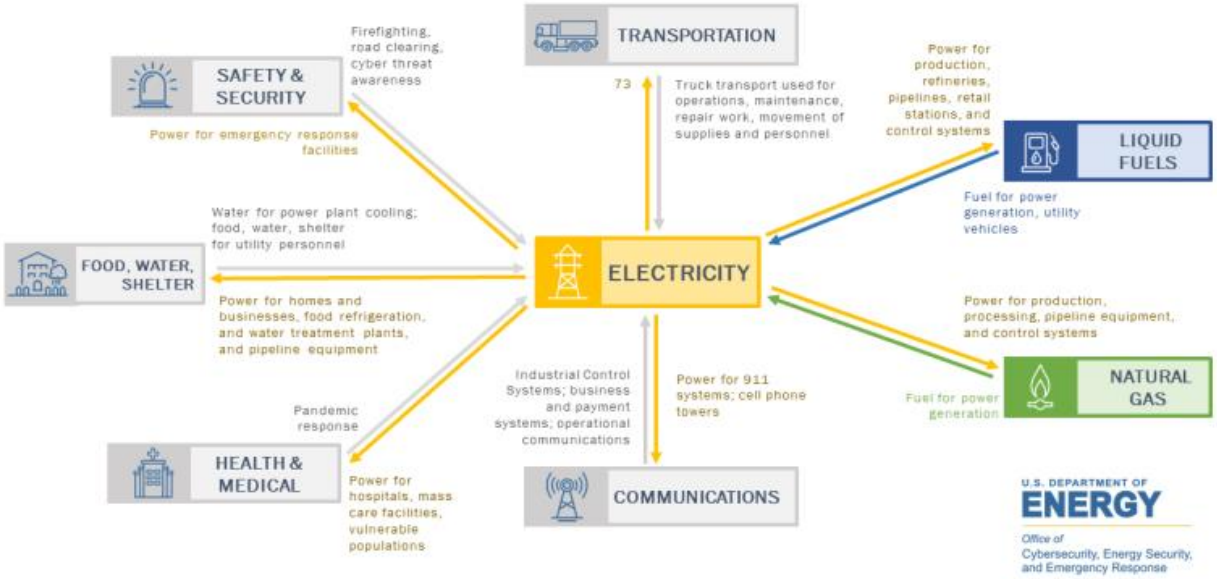
During the business continuity planning process, a range of hazards that could impact PacifiCorp facilities and service areas were identified and ranked, as shown in the following table. The scale is as follows: 1) low 2) moderate 3) high and 4) very high.

Hazard Risk Ranking					
Hazard	**Probability**	**Magnitude Severity**	**Readiness/ Preparedness**	**Duration**	**Risk Index**
Wildfire	4	2	1	3	2.85
Earthquake (5.0+)	2	4	2	4	2.8
Animal Impacts	4	2	1	1	2.65
Extreme Weather - High Temperature	3	2	1	3	2.4
Extreme Weather - Winter Storm	3	2	1	3	2.4
Landslide / Subsidence	3	2	1	3	2.4
Volcanic Eruption	2	3	1	4	2.35
Man-Made Physical Disruption	3	2	1	2	2.3
Power Outage	3	2	1	2	2.3
Man-Made Technological Disruption	2	3	1	3	2.25
Terrorist Act	2	3	1	3	2.25
Cyberattack	2	3	1	3	2.25
Dam or Levee Failure	1	4	1	4	2.2
Intruder	3	2	1	1	2.2
Trespassing / Theft at Facilities	3	2	1	1	2.2
Electromagnetic Magnetic Pulse (EMP)	2	3	1	2	2.15
Solar Storm	2	3	1	2	2.15
Flood	2	2	2	3	2.1
Pandemic Event	2	2	1	4	2.05
Supply Chain Interruption	2	2	1	4	2.05
Component Supply Chain Compromise	2	2	1	4	2.05
Drought	2	2	1	4	2.05
Tsunami	2	2	1	3	1.95
Civil Unrest	2	2	1	3	1.95
Severe Windstorm (58mph +)	2	2	1	3	1.95
Fire	2	2	1	2	1.85
Explosion	2	2	1	2	1.85
Severe Thunderstorms	2	2	1	1	1.75
Hazardous Materials Incident (HAZMAT)	1	2	3	2	1.7
Tornado	1	2	2	1	1.45

2.9.2 Community Lifelines Reliance on Electrical Power

PacifiCorp's risk profile is compounded by interdependencies on energy. One of the sectors identified by FEMA as a community lifeline, "the energy sector is uniquely critical because it provides an 'enabling function' across all critical infrastructure." *(Reference Presidential Policy Directive 21: Critical Infrastructure Security and Resilience*)

Transportation systems; communication systems; health and medical systems; sectors that provide food, water, and shelter; safety and security sectors; and other energy sectors such as natural gas and liquid fuel systems all depend on electric power to function. PacifiCorp has similar interdependencies on the other community lifelines as shown in the following graphic.



Examples of Critical Electricity Dependencies and Interdependencies

Source: U.S. Department of Energy, Office of Cybersecurity, Energy Security and Emergency Response, State Energy Security Plan Option Drop-In: Cross-Sector Interdependency Diagrams, May 2022, Found at website: State Energy Security Plan Optional Drop-In: Cross-Sector Interdependency Diagrams

2.9.3 Mitigation

PacifiCorp employs a variety of mitigation strategies to reduce the system's vulnerability to hazards and minimize the disruption of electrical distribution. Mitigation strategies related to physical hardening, transmission and wind loading, distribution, and operational mitigation are ongoing and continuously updated.

Additionally, PacifiCorp invests in multiple long-term projects to address system hardening related to wildfire risk. Projects are tailored to the wildfire risk for each state in the service area. Wildfire risk in each state and associated mitigation projects are documents in each state wildfire mitigation plan. *Reference state Wildfire Mitigation plans for details.*

3. INCIDENT MANAGEMENT STRUCTURE

Berkshire Hathaway Energy (BHE) has established an Emergency Coordination Guide (ECG) to provide support to business units during a crisis. The BHE ECG defines an incident command structure that is based on the FEMA NIMS incident management model. The BHE ECG provides direction and support for cross-company resource needs that can be obtained from unaffected business units and federal coordination. PacifiCorp's ERP and incident management structure can operate independently or subordinate to and in support of the BHE ECG. Depending on the level of activation, roles and responsibilities may be transferrable between the Executive Policy Group and the Emergency Coordination Center.

3.1 Berkshire Hathaway Energy Incident Management

The BHE Emergency Coordination Team provides the operating framework for the business and corporate functions to collaborate, coordinate and communicate during a situation that requires incident response. The PacifiCorp CEO, Presidents or designees participate in the BHE Emergency Coordination Team as PacifiCorp business unit representatives.

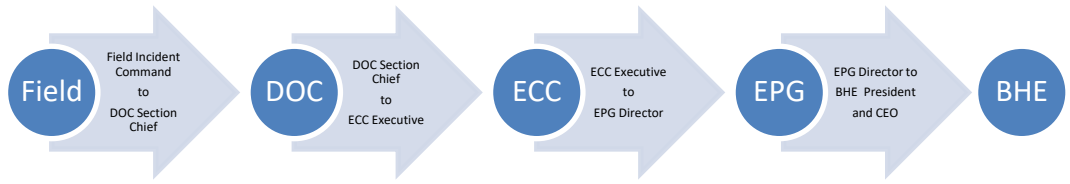
3.2 PacifiCorp Incident Management

The PacifiCorp emergency response framework provides a flexible and dynamic central coordination function that is activated for emergency events which may require additional coordination and resources beyond the capabilities of everyday business operations. PacifiCorp's emergency response framework is comprised of three tiers: the Department Operations Center (DOC), the Emergency Coordination Center (ECC) and the Executive Policy Group (EPG). The interface between each tier is critical for the success of overall emergency response.

Most emergencies start at the operational level through normal business organizational structures which expand during emergency events. To maximize internal coordination, streamline planning and resources, and re-prioritize objectives, PacifiCorp may initiate a response structure at the operational level, referred to as a DOC. One or more DOCs may be activated.

When incident complexity requires increased communication, operational or logistical support or incident coordination, an ECC can be activated, with or without a DOC, to coordinate a wide variety of responses. While both the DOC(s) and ECC operate under one common system, Pacific Power and Rocky Mountain Power maintain individual ECC facilities. Each utility ECC can operate independently from one another, complement each other, or activate as an overall PacifiCorp ECC for emergencies simultaneously impacting both service territories.

During large-scale emergencies that impact multiple business units or PacifiCorp as a whole, or when top level strategic decision-making and substantial external coordination efforts outside of the company are required, the EPG may be activated and incorporated into the incident command structure. The ECC Executive provides the EPG with incident updates, impacts to PacifiCorp business operations, and potential external needs that require EPG support. The EPG coordinates with internal and external stakeholders and provides strategic direction to business units and the ECC.



PacifiCorp Emergency Response Framework Hierarchy

3.2.1 Governance Transfer

Governance transfer allows leadership to continue essential functions during a catastrophic event. PacifiCorp' Emergency Management Business Continuity Plan establishes protocols for temporary transfer of leadership during a time of crisis when leaders, including the CEO or a President, may be unable to perform their duties. *Reference business unit continuity plans and the* Executive Emergency Manual *for more information on governance transfer.*

3.2.2 Lines of Succession

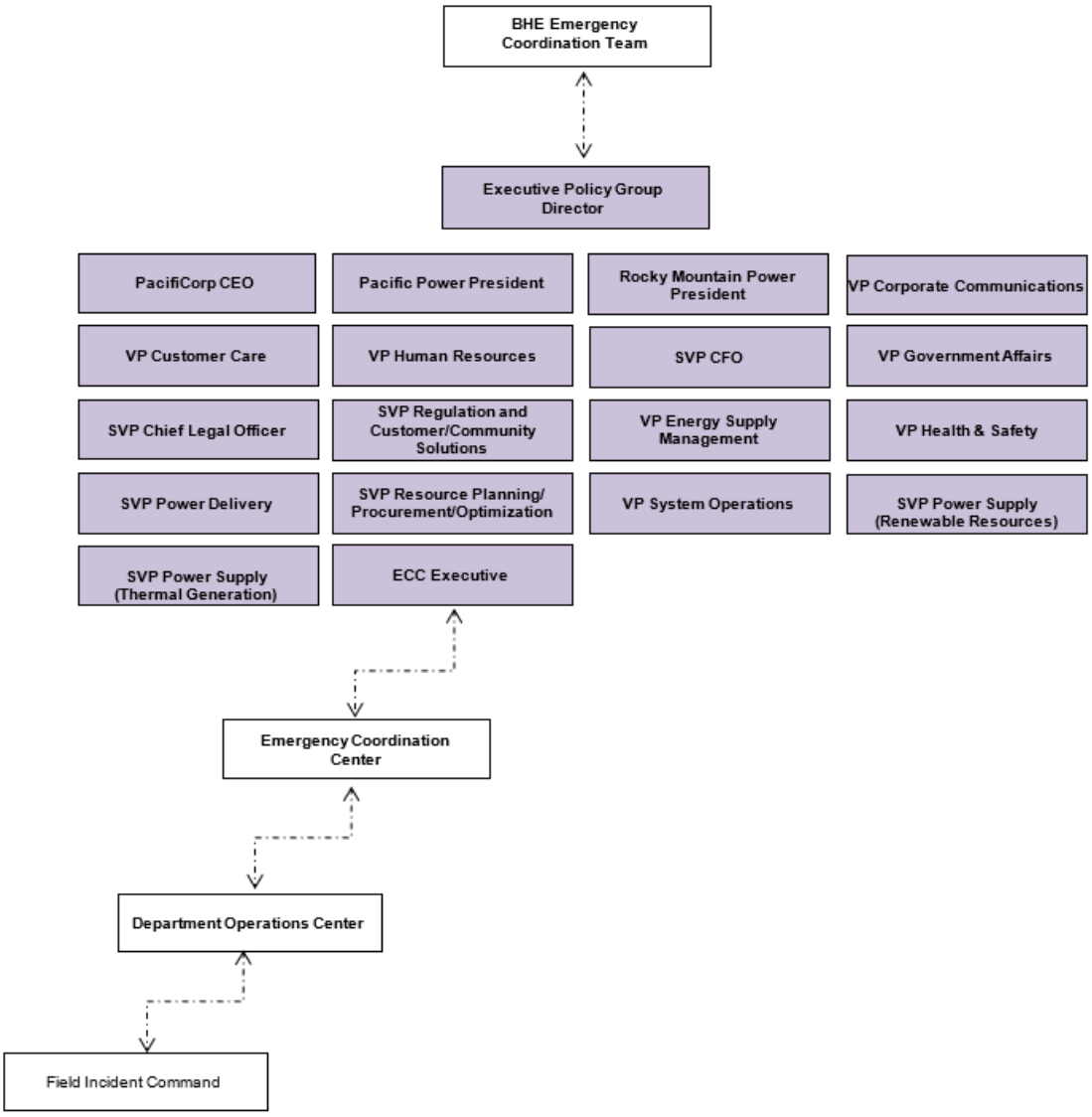
The following executives have roles in the EPG and ECC. If they are unable to fulfill their duties, the following lists their order of succession. These successors may also be used to provide rotational support for extended duration response.

Senior executives with response roles	**Alternates** *(in order of succession)*
PacifiCorp CEO	President, Pacific Power President, Rocky Mountain Power Senior Vice President, Power Delivery Vice President, Power Delivery Operations Vice President, Asset Management & Wildfire Strategy
Senior Vice President, Power Delivery	Vice President, Power Delivery Operations Vice President, Asset Management & Wildfire Strategy
Vice President, System Operations	Director, Main Grid Operations
Vice President, Power Delivery Operations	Managing Director, Power Delivery Support Managing Director, Delivery Assurance Managing Director Transmission and Distribution Grid Innovation and Strategy

3.3 Executive Policy Group

The EPG is responsible for (1) maintaining effective communication with external partners (i.e., BHE, regulatory bodies, federal, state, and local government executives), (2) providing strategic direction internally within PacifiCorp, and (3) maintaining critical business operations during the emergency event.

The EPG is singularly representative of PacifiCorp to allow leadership from both Pacific Power and Rocky Mountain Power to convene and to expedite coordination and collaboration efforts between the two business units. *Reference the* Executive Emergency Manual *for more information about the EPG.*



Executive Policy Group Organizational Chart Example

3.3.1 EPG Activation

While the dynamic nature of emergency events makes it difficult to establish concrete thresholds of which to activate the EPG, the following are examples of when it may be appropriate:

- BHE EOC activated for national threat or multi-platform impact
- High profile locations are impacted.
- Significant negative statewide or national media attention is anticipated.
- Multiple business units across PacifiCorp are impacted by the event.
- Anticipated or forecasted natural or human-caused events which may lead to political or reputational consequences. Threats or incidents related to compromised physical or cyber security.

If an ECC is activated, the request to activate the EPG will be coordinated through the ECC Executive. Whether the ECC is active or not, the PacifiCorp CEO or their designee**,** may proactively activate the EPG at their discretion in anticipation of an event or incident. The Alert Media system utilized for internal emergency notifications is also utilized to notify EPG members of initial activation.

3.3.2 EPG Deactivation

Upon completion of the incident, defined as management of the situation without the need for EPG support, the group will be deactivated. Any notes, documents or reports created by the EPG will be compiled and provided to emergency management for inclusion in any after action report and improvement planning.

3.3.3 Location and Facilities

Though EPG meetings will be hybrid (in-person and virtual) in nature, below are the primary and alternate meeting locations, respectively, for EPG members who are physically able to gather in person in Portland and Salt Lake City during an activation.

Pacific Power EPG Locations	
Primary location	**Secondary location**
Lloyd Center Tower 825 NE Multnomah Street Conference Center, 7th floor (LCT7) Portland, OR 97232	Portland Control Center 2nd Floor Conference Room 9951 SE Ankeny Street Portland, OR 97216
Rocky Mountain Power EPG Locations	
Primary location	**Secondary location**
North Temple Office 310C Conference Room 1407 W North Temple Salt Lake City, UT 84116	Wildfire Training Center 4800 W 500 South Salt Lake City, UT 84104

For PacifiCorp Executive Policy Group meetings, priority preference is to meet in-person for the respective business units and set up a Microsoft Teams video call to enhance interface. However, the ability to host meetings virtually will remain an option. In the event Microsoft Teams is inoperable, Emergency Management staff will set up a conference call with all participants. If there is a failure of the telecommunications infrastructure prohibiting a traditional conference call, satellite phones will be utilized to call into a pre-established conference bridge line. Emergency Management will help facilitate meeting setup regardless of whether the EPG meets in-person or virtually

When the BHE EOC is activated, it is recommended that PacifiCorp's EPG meetings are scheduled prior to the BHE EOC coordination calls.

3.3.4 EPG Roles and Responsibilities

The EPG is responsible for (1) maintaining effective communication with external partners (i.e., BHE, federal / national regulatory bodies, federal / national legislative bodies), (2) providing strategic direction internally within PacifiCorp, and (3) maintaining critical business operations during the emergency event.

CEO, President, or Designee
• Provide high level goals and objectives for overall response. • Establish appropriate policy directives in support of response priorities. • Authorize suspension or modification of PacifiCorp policies, if needed. • Overall approval authority for all internal and external strategic messaging. • Maintain communication with BHE leadership throughout the event. • Schedule and moderate recurring EPG meetings, as needed.
Communications
• Coordinate activities related to corporate and cross-business communications. • Coordinate external communications messaging to ensure the information needed to answer external stakeholders and media inquiries is consistent and available to company personnel. • Monitor local, national, and international reports (including social media engagement) about the event and breaking news, as necessary. • Develop, review, and coordinate the distribution of public messaging upon approval from CEOs or Designee(s). • Protect and enhance PacifiCorp's image, while realistically communicating what the company is doing to manage the situation and ensure safe and sustained service.
Customer Outreach
• Provide planning considerations, impact assessments, and any potential customer outreach implications to group discussions.
Human Resources
• Coordinate activities related to human resource needs or issues. • Provide status updates related to current or anticipated employee and/or union activities, issues, and needs.

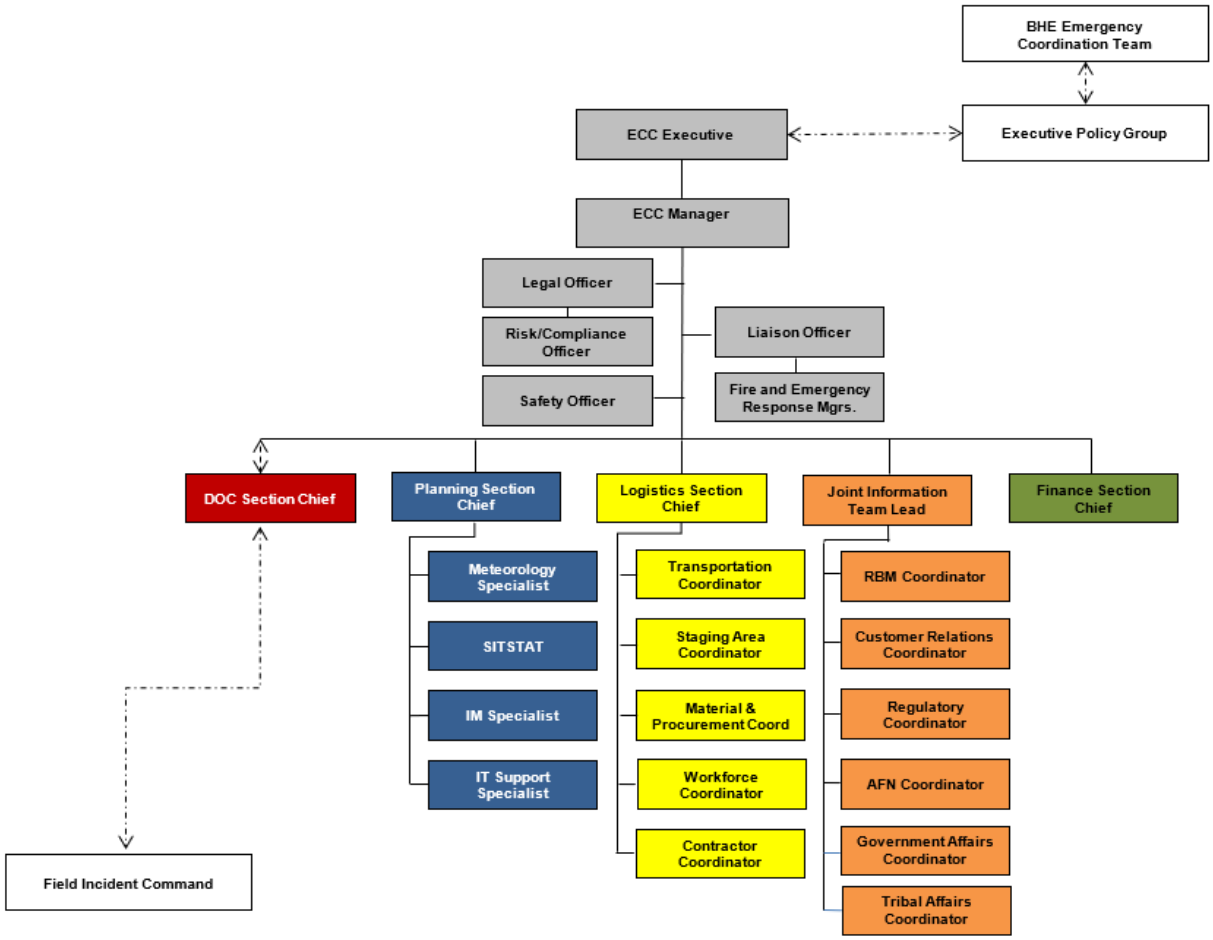
Finance
• Monitor the event for financial implications and impacts. • Provide status updates related to financial activities, issues, and needs. • Ensure costs are tracked and expenditures properly documented.
Government Affairs
• Coordinate activities related to governmental entities. • Provide planning considerations, impact assessments, and any potential governmental implications to group discussions.
Legal
• Coordinate activities related to legal needs and issues. • Assist with review and recommendations of corporate communications. • Provide status updates about activities, issues, and needs.
Regulatory
• Coordinate activities related to regulatory entities. • Provide status updates about activities, issues, and needs.
EPG Incident Management (IM) Specialist
• Schedule appropriate EPG meetings to align with existing strategic meetings as appropriate. • Assist with meeting agenda, documentation, and facilitation. • Coordination appropriate logistical requirements for virtual and/or in-person accommodations.

3.4 Emergency Coordination Center

The ECC provides coordination and support of the operational tactical response resources and reports current situational information to the EPG. The EPG provides strategic direction to the ECC and the ECC to the tactical teams (DOC). The ECC organizational structure is designed to be scalable based on complexity and internal or external stakeholder needs.

For less complex situations the ECC will operate without an EPG. Some EPG roles may be performed at the ECC level, for example Government Affairs Coordinator and Regulatory Coordinator. In some less complex situations, all ECC roles may not be required. In some cases, the roles and responsibilities for multiple ECC positions may be assumed by a single person. For example, a single person could assume the Finance Section Chief and Logistics Team Chief Roles and Responsibilities.

ECC and business unit staffing, resources and operational periods will be scaled to meet life safety and incident stabilization needs over the course of the event.



Emergency Coordination Center Organizational Chart Example

3.4.1 ECC Activation

The ECC may be activated when normal operations capabilities are exceeded or require immediate action due to severity, size, location, actual or potential impact on public health, welfare, or infrastructure. Response to incidents and emergencies are based on the potential impact or severity of an event.

Activation of the ECC can be requested by anyone who needs, or anticipates the need for, enhanced communication, operational or logistical support or incident coordination. Emergency Management may be requested to activate, or may recommend an activation of, the ECC in anticipation of an event or incident. ECC activation is approved by the executive that will assume the ECC Executive role for that incident.

The operational level at which the ECC may be activated is flexible. The ECC can be activated at any level as determined by the responsible ECC staff, and is based on potential or emerging strategic or tactical support requirements. The ECC may be activated concurrent to the activation of a DOC as described in section 3.5.

Reference the ECC Manager Checklist *for activation tasks.*

Levels of Operation	Description	Staffing Guidelines
LEVEL 1 Daily Operations	**Steady State** No event or incident is anticipated.	**Normal Staff** Situational awareness maintained by emergency management staff.
LEVEL 2 Monitoring (Watch)	**Elevated State** Emergency Management staff monitor credible threats, risks and/or hazards and may provide communications and/or coordination for a new or potentially evolving incident.	**Moderate Staff** Only select Emergency Management staff monitor an evolving event or support a new or potentially evolving incident.
LEVEL 3 DOC Activation (Warning)	**Enhanced State** A developing situation that requires DOC staff monitoring and/or resource planning; or due to actual or potential threats, risks, or hazards an incident requires coordination extending beyond normal DOC operational work duties.	**Mid-level Staff** DOC level support staff and emergency support functions or liaisons, as needed.
LEVEL 4 ECC Activation	**Full Activation** Due to severity, size, location, or actual or potential impact of public health, welfare, and infrastructure, an incident requires direct support from ECC staff functions beyond DOC and Emergency Management level staff.	**Full Staff** Full ECC level support functions and interagency liaisons.

3.4.2 ECC De-Activation

The ECC will be deactivated, and the incident will be closed once local district operations can provide oversight of the operational response aligned with normal daily operations, without the need for ECC support or direction and when expanded internal and stakeholder coordination is no longer required.

3.4.3 ECC Locations and Facilities

The ECC may be virtual, or in person, but most commonly the ECC is structured as a hybrid activation offering both virtual and physical options.

Pacific Power ECC Locations		
Primary location	**Secondary location**	**Alternate Locations** *(incident dependent)*
Portland Control Center: First Floor Conference Room, Portland, OR	Bend Service Center* Bend, OR **In a Cascadia Subduction Zone earthquake*	Yakima, WA Klamath Falls, OR North Temple Office, Salt Lake City, UT
Rocky Mountain Power ECC Locations		
Primary location	**Secondary location**	**Alternate Locations** *(incident dependent)*
North Temple Office (NTO): 260 Control Center Conference Room, Salt Lake City, UT	Wasatch Restoration Center, Salt Lake City, UT	American Fork, UT Ogden, UT Casper, WY Portland Control Center, Portland, OR

3.4.4 ECC Roles and Responsibilities

The ECC is led by the ECC Executive, who has overall responsibility for incident coordination and is supported by the Command and General Staff. An overview of roles and responsibilities for each ECC position is listed below. *Reference ECC Personnel Checklists for tasks related to each ECC position.*

ECC Executive

The ECC Executive's responsibility is the overall management of the emergency incident and the assessment of the incident priorities. This position ensures the separation and integrity of both the ECC and the Executive Policy Group (EPG) if activated. The ECC Executive serves as the primary point of contact for the sharing of information with the EPG if activated.

Command Staff

Overall management of the incident includes all command staff functions.

ECC Manager
The ECC Manager's responsibility is to facilitate and manage the functions of the ECC as appropriate to support the implementation of the situation report (SitRep) and in support of the ECC Executive.
Safety Officer
The Safety Officer is responsible to develop and recommend measures to ensure personnel safety and occupational health of not only response workers, but also the public, and to anticipate, recognize, assess and control hazardous and unsafe conditions or situations. There is only one Safety Officer for each operational period. However, Assistant Safety Officers may be requested due to a specific skill set required during incident response. (e.g., air operations, occupational health, hazardous substances, and sanitation).
Legal Officer
The Legal Officer is responsible for providing advice and direction on all matter of a legal nature including claims, legal requirements relating to the emergency response, investigations, natural resource damage assessment, major procurement contracts, insurance coverage, and review of information releases to the media, government agencies, and the public. The Legal Officer will seek guidance from the ECC Executive on level of authority, actively seek input, advice, and local knowledge from DOC Section Chiefs, and recognize and reconcile differences in authority for individual responders.
Risk/Compliance Officer
The Risk/Compliance Officer is responsible for investigating 3rd party liability claims made by customers associated with an event. The Risk/Compliance Officer will work directly with the Legal Officer for investigation purposes. In the event of an investigation, the Risk/Compliance Officer will work with local operations to retain evidence and coordinate with on scene external investigators as well as investigators retained by the utility to investigate and document a scene.
Liaison Officer/Fire and Emergency Response Managers (FERMs)
The Liaison Officer is assigned to the incident to be primary coordinator for the liaison network, including assisting and cooperating with Agency Representatives. The Fire and Emergency Response Managers manage and support relationships with external first responder stakeholders, including Fire and First Responder agency leadership. FERMs engage in incident field response, working closely with a Fire Incident Management Team (IMT) to collect and report critical information to the Liaison Officer to share with the ECC. Supported by the FERMs, the Liaison Officer is a conduit for information and assistance between organizations and does not normally have delegated authority to make decisions on matters affecting an organization's participation in the incident. However, the ECC may assign additional responsibilities or authorities to the Liaison Officer or FERMs to effectively manage complex incidents. Due to the complexity or scope of the incident, the FERMs may require one or more personnel in the field, to maintain coordination and communication needs.

The Liaison Officer and FERMs will act as a Company Representative when supporting multi-jurisdictional incidents to interface with agency Liaison Officers in supporting and coordinating all efforts on behalf of PacifiCorp.

General Staff

The General Staff represents and is responsible for the functional aspects of the ECC. Each General Staff section is led by a Section Chief who reports to the ECC Executive. These individuals are responsible for managing all tasks within their functional areas.

The PacifiCorp ECC General Staff consists of five sections: the Joint Information Team, Planning, Logistics, Finance, and the Department Operations Center (DOC). In an expanding incident the Command Staff will first establish the DOC. The remaining sections are established as needed to support the mission.

Joint Information Team
The Joint Information Team (JIT) is responsible for managing, developing, and releasing information about the incident to the media and public, to incident personnel, and to other appropriate agencies and organizations. *Reference the PacifiCorp Joint Information Team Response Guidelines for more information.*
Joint Information Team Lead
The Joint Information Team Lead (JIL) will coordinate with corporate communications on the established process for the development of media releases, specific to individual events. The JIL is responsible for developing and releasing information about the incident, such as estimated restoration times and potential safety hazards, to the media and public, to incident personnel, and to other appropriate agencies and organizations. All media and stakeholder risk perceptions, technical content of external messaging mediums, and information used for public communications will be under the responsibility of the JIL. As necessary during emergency incidents, the JIL will establish and manage the Joint Information Team (JIT).
Regional Business Manager Coordinator
The Regional Business Manager (RBM) Coordinator is a member of the JIT and a key channel of communication to the ECC for information as it relates to managed accounts, critical customers, and community needs. The RBM is responsible for communicating all priorities, needs, and concerns related to the incident during the response and restoration planning process.
Customer Relations Coordinator
Part of the JIT, the Customer Relations Coordinator is responsible for coordinating information about the incident to customers, resolving incident concerns with appropriate and timely information, and supporting the ECC with customer data for evaluation during the incident planning process.
Regulatory Coordinator
A member of the JIT, the Regulatory Coordinator is responsible for the accurate and timely filing of all official regulatory documents and communications associated with an incident to all appropriate regulatory agencies i.e., Public Utility/Service Commissions and other organizations as may be determined by the ECC. The Regulatory Coordinator will coordinate,

compile, and track all submissions related to the emergency incident, including providing research support, reports, and other official documents as may be warranted. The Regulatory Coordinator will coordinate with the state regulation group to identify additional communications to Public Utility/Service Commissions. The Regulatory Coordinator will also support the ECC's Legal Officer through review of all legal documents involving compliance issues required by regulatory agencies.
Access and Functional Needs (AFN) Coordinator
The AFN Coordinator is responsible for advising the ECC on unmet needs of customers with medical and other access and functional needs impacted by the incident; and coordinating with the JIT, Liaison Officer, the local emergency operations center, community-based organizations, health and human services departments and other service providers, as appliable, on AFN needs that have been escalated to the ECC.
Government Affairs Coordinator
The Government Affairs Coordinator, as a member of the JIT, is responsible for communicating certain official regulatory documents and communications associated with an incident as compiled by the Regulatory Coordinator to the governor's office, state legislators and Tribal governments in the affected communities of the incident.
Tribal Affairs Coordinator
The Tribal Affairs Coordinator will support the Regional Business Managers and Government Affairs Coordinator in outreach to Tribal Nations and serve as the emergency contact for Tribes and Indigenous organizations in PacifiCorp service territories. The Tribal Affairs Coordinator will also provide key updates to the JIT and the ECC.

Logistics Section
The Logistics Section provides incident support needs such as facilities, transportation, food, communications, and equipment.
Logistics Section Chief
The Logistics Section is responsible for ensuring adequate resources including personnel, supplies, and equipment and are aligned with supply chain business unit of the company. The Logistics Section Chief is responsible to support the response efforts by managing facilities, services, personnel (both internal workforce and contract personnel), material, transportation, staging areas, and resource mobilization.
Transportation Coordinator
The Transportation Coordinator is under the direction of the Logistics Section Chief and is responsible to support the response efforts by managing equipment and vehicles, fueling services, transportation of personnel, supplies, and equipment, recording equipment usage, including contract equipment assigned to the incident, and implementing the Transportation Plan. This position provides information and planning to the Logistics Section Chief in support of the development of the SitRep.
Staging Area Coordinator
The Staging Area Coordinator is directed by the Logistics Section Chief and is responsible for the setup, maintenance, and demobilization of incident facilities, e.g., base camp and staging areas. Each location will be assigned a manager who reports to the Staging Area Coordinator and manages the facility's operation. This position provides information and planning to the Logistics Section Chief in support of the development of the SitRep.

Material & Procurement Coordinator
The Material & Procurement Coordinator is under the direction of the Logistics Section Chief and will focus their efforts on procuring equipment, materials, and supplies to support emergency operations. This position will ensure and assist the DOC staff and field responders obtain all material, equipment, and supplies to support emergency operations and restoration efforts. The Material & Procurement Coordinator maintains an inventory of supplies. Coordination of resource accountability occurs between this position, DOC Operations staff and the Finance Section Chief and the DOC Operations Finance Specialist.
Workforce Coordinator
The Workforce Coordinator is directed by the Logistics Section Chief and is responsible for managing all PacifiCorp workforce personnel to support response and restoration efforts. Coordinating with DOC operations staff and the ECC Contractor Coordinator, this position develops and manages the Workforce Support Plan. The Workforce Coordinator provides regular information and planning to the Logistics Section Chief in support and development of the SitRep.
Contractor Coordinator
The Contractor Coordinator is under the direction of the Logistics Section Chief and is responsible for the management of all contractors to support response and restoration efforts. Coordinating with DOC staff, develop and manage the SitRep. The Contract Coordinator provides regular information and planning to the Logistics Section Chief in support and development of the SitRep.

Planning Section
The Planning Section collects situation and resource information and complies with the information for use in formal briefings and situation reports.
Planning Section Chief
The Planning Section Chief is responsible for the collection, evaluation, dissemination, documentation, and use of incident information. The Planning Section Chief is the primary node for information management, which may include both classified and non-classified information. The Planning Section Chief will utilize specialists or coordinators to support this section of the ECC.
Meteorology Specialist
Meteorology Specialists are the primary node for weather related impacts and information management associated with an emergency event. Meteorologists are responsible for consulting, analyzing, collecting, processing, and organizing information associated with incidents where weather, and weather forecasts, will have impacts on the severity and duration of real and potential system emergencies.
SITSTAT
The WIC supports components of the SITSTAT. The WIC consists of operational specialists with specific skills needed to support maintaining situational awareness throughout the incident response. If necessary, these operational specialists may support a separate unit referred to as the Situation Unit. This role will update incident maps, gather data on the incident, and research relevant field updates. The WIC will present information in verbal or written format to support the ECC.
Incident Management Specialist

The Incident Management (IM) Specialist is responsible to oversee document management and maintain accurate, up-to-date incident documentation that will constitute the incident record, such as the situation report (SitRep). Some documents may originate in other DOCs or Sections. This unit shall ensure each DOC or ECC Section is maintaining and providing appropriate documents for inclusion in the incident file.
Information Technology Support Specialist
The Information Technology (IT) Support Specialist is responsible to oversee and direct software and computer systems and hardware as necessary to support the emergency incident. This position will provide computer and network services and troubleshooting to ensure that the appropriate hardware and software are available to support operations. In addition to providing technical support, the IT Support Specialist will define, implement, and maintain a data management and archival process that may include developing a centralized server-side repository for all data (e.g., files, maps, photos, database files) and performing periodic backup copies of incident data and database files. The IT Support Specialist will manage and maintain the use of stand-alone or network computers, research network problems, and assure compliance with operational and security requirements.

Finance Section
The Finance Section manages financial aspects of the incident, such as cost analysis, claims support, personnel costs and financial record keeping.
Finance Section Chief
The Finance Section Chief is responsible for all financial, administrative, and cost analysis aspects of the incident and supervising DOC Finance Specialists. The Finance Section Chief will collect all cost data, perform cost effectiveness analyses, and provide cost estimates and cost saving recommendations for the incident. This role will also manage and direct all administrative matters pertaining to compensation for injury and claims related activities, vendor contracts, leases, and fiscal agreements. The Finance Section Chief shall execute all procurements in accordance with the policies and procedures of PacifiCorp

3.4.5 ECC Tools

The PacifiCorp ECC Binder and ECC MS(Microsoft)Teams folders for each utility contain the following ECC tools:

- ECC activation checklists
- Notification templates
- ECC internal and external contact lists
- ECC agendas
- ECC position descriptions and checklists
- ERP
- PSPS Execution Playbook
- Incident Command System (ICS) forms
- Asset tracking tools
- Situation Report template
- Incident Action Plan template

Physical versions of the ECC Binders including hard copies of the documents notated above are located at the following locations:

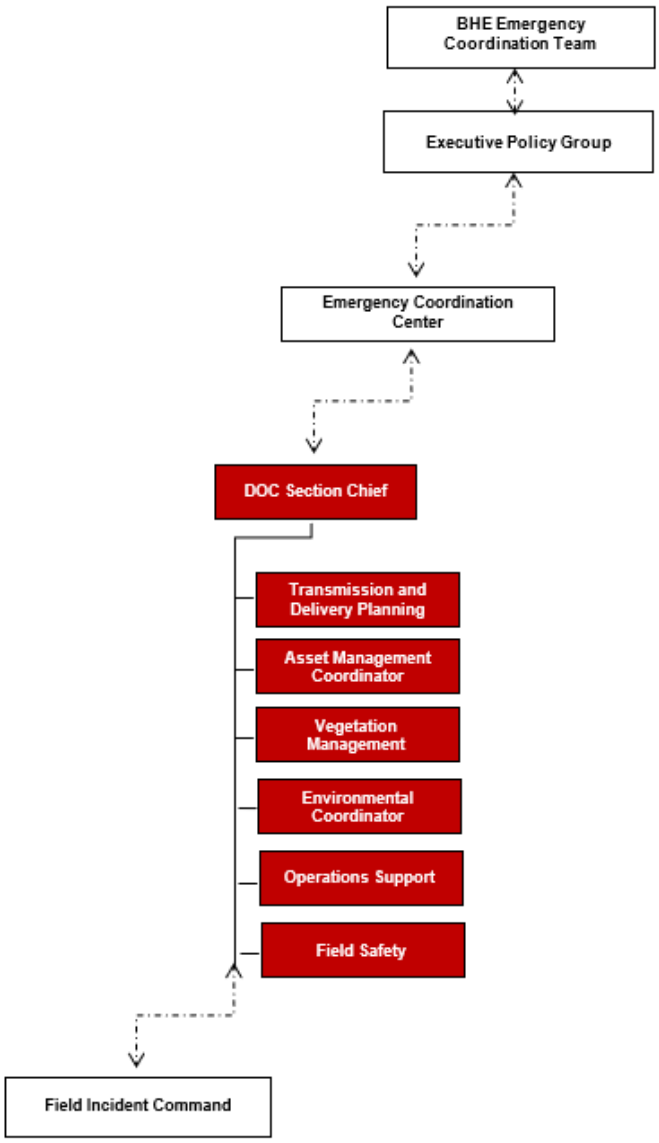
Pacific Power ECC Binder Locations
• Portland Control Center (PCC): First Floor Conference Room, Portland, OR • Grants Pass Office, Grants Pass, OR • Bend Service Center, Bend, OR
Rocky Mountain Power ECC Binder Location
• North Temple Office (NTO): 260 Control Center Conference Room, Salt Lake City, UT

3.5 Department Operations Center

Department Operations Center(s) are responsible execution of the operational response. This section represents the on-scene specialists who are physically assessing and correcting the problem. The DOC provides operational guidance and support to the tactical response resources. This is achieved by overseeing all activities and resources needed to support assessment and response to the physical problem.

When the ECC is activated, the DOC will report operational updates through the DOC Section Chief, to the ECC and coordinate planning with other DOC Section Chiefs as appropriate based on the needs of the incident. The ECC structure is set up to support DOC activities and expand internal and external coordination as required by size and complexity of event.

In the event an ECC is not activated, the executive leadership overseeing the respective DOC chief will receive appropriate operational updates and provide strategic oversight through normal business structure reporting. The DOC organizational structure is designed to be scalable based on situational needs. If a DOC's response coordination capabilities are exceeded, the ECC will be activated to support the DOC.



Power Delivery Department Operations Center Organizational Chart Example

3.5.1 DOC Roles and Responsibilities

DOC staff are responsible for the overall management of the response at the tactical/operational level. These positions are those responsible for organizing and managing responding operators/technicians.

Power Delivery DOC
Historically, a Power Delivery DOC has been activated to support expanded operational needs during an incident response. Following is a sample organizational chart of a Power Delivery DOC. Should other DOCs need to the activated, the response structure would be determined and scaled to meet the unmet needs of the incident.

DOC Section Chief
The DOC is responsible to directing all tactical operational aspects of the incident. The DOC Section Chief (DSC) is responsible for the management of all operations directly applicable to the primary efforts of restoration and repair of utility assets and infrastructure impacted by an emergency event. The DSC will direct all operational plans, activate all units within the DOC section, continually evaluate restoration efforts, and approve the requisition and release of all resources.
Transmission and Distribution Planning Coordinator
The Transmission & Distribution (T&D) Planning Coordinator is responsible for providing circuit planning and consultation to the DOC Section Chief in support of Operation's strategic response and planning. The T&D Planning Coordinator will collect all system information and data, propose system modification options and configurations, provide circuit design, and verify as-built construction of circuit systems and infrastructure. This role supports all matters pertaining to operational activities including the development of the SitRep.
Asset Management Coordinator
The Asset Management Coordinator is responsible for providing evaluation and consultation to the DOC Section Chief in support of Operation's strategic response and planning. The Asset Management Coordinator will collect all system information and data concerning conditions and reliability of circuit systems and infrastructure. This role will also support all matters pertaining to operational activities including development of the SitRep
Vegetation Management
Vegetation Management is responsible to develop and implement the vegetation management portion of the SitRep, to assign resources within the impacted service area to support the DOC operations response strategy, and to report on the progress of inspections, operations, condition and corrections, hazards, and accessibility within the impacted area
Environmental Coordinator
The Environmental Coordinator is responsible for all environmental matters during an incident, including strategic assessment, surveillance, and environmental monitoring and permitting. This position will provide technical expertise to ensure that the technical approach to environmental issues is effective and acceptable to stakeholder agencies. The Environmental Coordinator will support the SitRep by developing strategic environmental plans to support the incident. This role directs, organizes, and manages all environmental concerns to protect public and personnel health, welfare, and the environment.
Operations Support
Operations Support assists the DOC with logistical needs such as transportation, staging areas, materials and procurement, workforce and contracts. See the ECC Logistic Section for positions descriptions for each of these functions.
Field Safety
Field Safety is responsible for implementing measures to ensure personnel safety and occupational health of response workers and the public; and to anticipate, recognize, assess and control hazardous and unsafe conditions or situations. Field Safety personnel may have responsibilities pertaining to specialized areas (e.g., air operations, occupational health, hazardous substances, and sanitation) to ensure the safety and accountability of operations personnel during the entire duration of the incident. Under the direction of the Safety Officer, the Field Safety role will develop measures to assure personnel safety by providing safety perspective, risk management and operational priority consideration.

3.5.2 DOC tools

Each utility maintains files in MSTeams that contain DOC tools including, but not limited to:

- DOC coordination meeting agendas
- DOC situation report templates
- Event resource trackers

Reference the **Pacific Power ECC files** *and* **Rocky Mountain ECC files**.

3.6 Field Incident Command

The Field Incident Commander is delegated authority to manage all incident-related activities, to establish priorities and to allocate company resources to resolve the incident. The field response structure is intended to give the Field Incident Commander flexibility to scale the response as needed.

3.6.1 Field Incident Command Roles and Responsibilities

Field Incident Command
The Field Incident Command is under the direction of the DOC Section Chief and is responsible for all tactical field operations directly applicable to the primary efforts of restoration and repair of PacifiCorp assets and infrastructure impacted by an emergency event. The Field Incident Command is responsible to support the response efforts by implementing all SitRep tactical priorities in accordance with operational protocols.

4. SAFETY

Safety of the public and employees is the number one priority of PacifiCorp. Employees responding to an incident are qualified to identify electrical equipment and the hazards of electrically energized components to ensure both the safety of the employee and the safety of the public. PacifiCorp has processes to prioritize response to reported public safety hazards.

In a major event or disaster internal resources from adjacent districts, or contract resources, can be deployed to evaluate hazards and stay on scene for the safety of the public until the situation can be made safe or permanently repaired. *Reference the position descriptions above for ECC Safety Coordinator and DOC Field Safety.*

To support the company's commitment to safety, PacifiCorp implements the following safety considerations for field crews and ECC responders to prevent work related injuries:

- Contractor/external crews' safety
- Defensive driving
- Employee preparedness
- Ergonomics
- Equipment inspections
- Employee wellness

- Environmental safety
- Fatigue management
- Metering safety
- Office safety
- Occupational health and safety standards
- Product approval
- Sanitation

5. DAMAGE ASSESSMENT and RESTORATION PRIORITIES

5.1 Damage Assessment Priorities

PacifiCorp assesses damages in a prioritized fashion that includes first priority evaluation of public safety hazards such as reports of lines down. Qualified personnel are deployed to identify the hazard; standby until made safe, if electrically qualified; and may repair, or make safe, the public safety hazard. Staffing contingencies include properly trained single person resources, crew resources and support resources. Resources are prioritized based on a combination of factors that include the number of customers impacted, anticipated scale and type of damage, and type of equipment impacted.

PacifiCorp has policies and procedures to ensure a timely response to emergency outages and to coordinate the necessary personnel and resources to ensure timely restoration. Steps will be taken to ensure restoration is coordinated based on expected outage duration and level of damage to determine when an appropriate handoff or escalation is needed. In general, priorities are set such that service is restored first to critical and essential customers, and that the largest number of customers receive service in the shortest amount of time. The system operator and/or local operations managers will coordinate field response. Crews are assembled in the area(s) being impacted by the outage. Based on expected outage duration and material damage, the logistics are handled by the ECC.

5.2 System Restoration Priorities

Though there may be exceptions, the following represents system restoration priorities, from highest priority to lower priority:

- Transmission substations and associated lines.
- Sub-transmission substations and associated lines.
- Three-phase feeders.
- Single-phase primary lines.
- Service wires on the low-voltage side of the transformer.

Exceptions to this priority listing could include situations endangering life and property, critical customers, and restoration performed at the request of civil authorities. These exceptions shall be handled by the ECC on a case-by-case basis.

5.3 System Restoration Guidelines for Critical Customers

Critical customers are those who rely on PacifiCorp to provide electrical power for the vital sustainment of life, essential service to a community or large revenue customers who are important financially to both the company and the community. There are three categories of critical customers that PacifiCorp serves: 1) customers with access and functional needs, 2) critical infrastructure customers and 3) key customers.

6. RESOURCING and MUTUAL ASSISTANCE

6.1 Assistance Agreements

In cases where an incident exceeds the district's capability to respond, requests for assistance from outside the district which would include internal or external resources will occur. As such, PacifiCorp is a party to several pre-existing mutual assistance agreements. These agreements outline arrangements and details to provide aid before, during and after an emergency and to facilitate the rapid mobilization of equipment and supplies.

- Western Region Mutual Assistance Agreement (WRMAA)
- Inter-Company Agreement
- California Utility Emergency Association (CUEA)
- Idaho Mutual Assistance Agreement
- One Utah Mutual Assistance Agreement
- Wyoming Rural Electric Association Mutual Assistance Agreement

6.2 Mutual Assistance Activation

Upon initiation of a major incident, emergency management will evaluate and document if mutual assistance would expedite restoration and will continuously re-evaluate mutual assistance requirements with the support of the DOC Section Chief. The activation of mutual assistance will occur if the response's requirements are beyond resource capabilities. After an incident occurs which would require mutual assistance beyond the nearby or adjacent utility-to-utility level, the PacifiCorp CEO will notify the Berkshire Energy CEO of the identified need for mutual assistance.

When utilizing mutual assistance, the procedures for each mutual assistance entity (intercompany, WRMAG, CUEA) will be followed. Such procedures are outlined in each respective signed mutual assistance agreement. Examples include, but are limited to:

- Procedures for requesting and providing assistance
- Financial procedures, i.e.: charges, taxes, payment, invoices, accounting, auditing
- Procedures for deactivation

The following escalation order for mutual assistance will be used:

1. Internal Mutual Assistance request generated
    a. Berkshire Hathaway Energy Emergency Operations Center may activate for the incident.
2. Mutual Assistance from local area utilities
    a. Direct contact with other utilities
    b. Provide letter as formal request
3. Regional Mutual Assistance Group (RMAG)
    a. Regional Mutual Assistance Group (RMAG) activation at request of PacifiCorp CEO
    b. Submit assistance information via the online Ramp-Up tool for immediate use
    c. California Utilities Emergency Association requests may also happen if RMAG does not activate
4. National Response Event (NRE)
    a. Level 1 Activation Criteria
        i. Significant threat is forecast to occur, where expected or actual resource requirements are greater that what the RMAG(s) can supply; and resources from other RMAGs are available without causing constraints or competition between RMAGs.
        ii. While there may not be resource competition between RMAGs, this level of NRE is used for incidents (due to severity, reputational capital risk, impact on customers., etc.) that require enhanced situational awareness and engagement by member companies.
    b. Level 2 Activation Criteria
        i. Requesting CEO contacts EEI President to discuss the need for a Level 2 NRE activation.
        ii. The event is expected to or has impacted two or more RMAGs; and
        iii. Resource requirements are greater than what RMAGs involved can provide; or
        iv. Multiple events create a resource constraint or competition between RMAGs.

6.2.1 California State Office of Emergency Management Notification

State offices of emergency management will be notified through emergency notification procedures. Such state offices may include the California Utilities Emergency Association within the California Utility Coordination Center or affected State Emergency Support Function 12/Public Utilities Commission.

6.2.2 CUEA Mutual Assistance Activation

The activation checklist at the end of the CUEA agreement is used to initiate activation of this mutual assistance option.

6.2.3 WRMAA Activation

PacifiCorp utilizes the online Ramp Up tool to send and receive mutual assistance from the WRMAA.

6.2.4 National Response Event (NRE) Command Facilities

The preferred primary location for holding an NRE is the Edison Electric Institute (EEI) headquarters due to the proximity to government resources and EEI staff. The criteria for consideration of alternative sites should include impacted or potentially impacted areas, travel time for responding personnel, etc. Alternate site host companies will provide logistical support for their facilities and assist in obtaining meals and lodging for NRE activation teams.

EEI and NRE Primary Facility

The EEI headquarters is located in Washington D.C. and will be the primary location for NRE Command and Control.

EEI and NRE Secondary Locations

Secondary locations for the NRE are in:

- Ashburn, VA (Equinix DC10)
- Herndon, VA (Dominion Energy)
- Portland, OR (PacifiCorp)
- Dallas, TX (Oncor)
- Chicago, IL (ConEd)
- Las Vegas, NV (NV Energy)
- Oakland, CA (PG&E)

PacifiCorp is the host utility for the site which is located at the NRE Alternate Facility Portland, Oregon.

PacifiCorp Lloyd Center Tower,
7th Floor Conference Rooms
825 NE Multnomah Street
Portland, OR 97232
Cell phone: Emergency Management on-duty staff: (503) 331-4498

NRE Portland Alternate Facility Procedures

Emergency Management staff will be the EEI NRE team's primary contact before arrival. The emergency management duty phone number is published in the EEI NRE Playbook and will be the first notification that a team is en route. Upon notification emergency management staff will coordinate:

- Activate the Emergency Coordination Center (if not already activated)
- Ensure availability and functionality of the facility
- Coordinate arrival of the team
- Act as liaison between EEI and PacifiCorp
- Coordinate host actions in accordance with the EEI NRE Playbook by activating the NRE Coordination Center at Lloyd Center Tower.

Reference the NRE Playbook for details.

6.3 Roles and Responsibilities

6.3.1 Emergency Management

- Identify the need to send or receive mutual assistance based on incident requirements
- Request support from lowest possible level based on circumstances
- Receive initial request for assistance from other member utilities
- Initiate mutual assistance requests through the following procedures as appropriate:
    1. Intercompany assets (*Refer to Inter-Company Mutual Assistance Agreement)*
    2. Local area utilities
    3. Regional mutual assistance entities
        - California Utility Emergency Association for events within California *(Refer to CUEA Mutual Assistance Agreement)*
        - Western Region Mutual Assistance Group *(Refer to Western Region Mutual Assistance Agreement)*
            - Review the WRMAG resource list
- Request ECC Finance to begin work order creation and tracking

6.3.2 DOC Section Chief

- Identify available crews, equipment, and material upon receiving request for support
- Coordinate outbound response and assistance

7. INTERNAL COMMUNICATION PROCEDURES and SYSTEMS

PacifiCorp follows a comprehensive communications plan internally for the coordination before, during and after an incident with communication redundancies in place.

7.1 Receiving Notification Procedures

PacifiCorp personnel will receive notification of a potential event as early as feasible prior to activation of an event. Information provided will include the current or forecasted weather conditions and additional key variables triggering an event, the affected area, customer count and the date and time of the event.

PacifiCorp provides early monitoring and situational awareness of wildfires and potential hazards through our WIC, which will provide credible situational awareness updates to stakeholders in a specified cadence.

Reference the WIC Standard Operating Guides.

7.2 Pushing Notification Procedures

Upon identification of an incident, a typical notification will occur in the following order based on level of severity:

1. District or Area Manager
2. Wires/Substation/Grid Operations Director
3. Emergency Coordination Center Executive or Emergency Manager Duty Officer
4. Appropriate Vice President/Managing Director
5. Chief Executive Officer
6. Berkshire Hathaway Energy Chief Executive Officer

The emergency management duty officer will initiate the appropriate notification process. *Reference the* Emergency Management Duty Officer Guidance.

7.3 Physical and Cyber Security

PacifiCorp infrastructure is a target for both physical and cyber-attacks. Emergency Management monitors the conditions and operating status of our infrastructure. Threats and physical or cyber incidents are coordinated with the Chief Security Office, who is responsible for investigations and aspects of cyber response. Physical or cybersecurity incidents should be immediately reported to the Global Security Operations Center (GSOC) at 855-767-0538 or by email at securityalerts@brkenergy.com.

Reference Annex 01 External Emergency Coordination and Communication for notification processes to external partners, customers, and regulatory agencies.

7.4 Internal Emergency Communication Systems

The PacifiCorp Procedure: Communication Planning provides a framework to ensure critical communications are sustained during emergency incidents. BHE has grouped communications capabilities into four categories: Primary, Alternate, Contingency, and Emergency (PACE). Each category provides different resources if the systems in the higher-level fail. The table below lists PacifiCorp's internal communication capabilities and how each fit into the PACE framework. Following the table is a description of each capability. These communication systems are staged, maintained, and periodically tested to facilitate communications during an incident.

Mode of Communication	Primary	Alternate	Contingency	Emergency
Landline VOIP	X			
Microsoft Teams	X			
Cellular Phones	X			
Email	X			
Company Radio Systems	X			
GETS		X		
WPS		X		
FirstNet		X		
Satellite Phones			X	
Starlink			X	
Mass Notifications				X
Amateur Radio				X
SHARES				X
Conference Bridges				X

7.4.1 Primary Communication Modes

VoIP Telephones	PacifiCorp utilizes a VoIP telephone system that allows for calls to be made over an internet connection instead of over traditional phone lines or cellular connections.
Microsoft Teams	MSTeams is PacifiCorp's primary tool for can be utilized for internal day-to-day instant messaging to individuals and groups and on-demand or scheduled audio and web conferencing. Pertinent information during response and recovery is stored and accessible to ECC personnel in MSTeams. Some information is preloaded onto the site, however all ECC members have the ability to save whatever they might need into their specific position's folder. After the close of event, all MSTeams folders and documents are archived in significant events and stored.
Cellular Phones (Voice/Text)	Employees carry cellular telephones and have access to satellite phone communications at many key locations.
Email	PacifiCorp's internal email system can be accessed both internally and remotely, on company issued devices, via VPN through dual factor authentication.
Company Radio Systems	The PacifiCorp radio system is designed with redundant systems and power backups for emergency situations, including VHF/UHF, digital and HF radio capabilities. Pacific Power/Rocky Mountain Power personnel utilize vehicles equipped with two-way radios under Federal Communications Commission license. These radios can communicate with Grid Operations, Hydro Control Centers, surrounding mobile units and portable radios, via fixed base stations which are located at Pacific Power/Rocky Mountain Power facilities, and with PacifiCorp's microwave radio system.

	The PacifiCorp radio communications section has conducted a study which shows the radio system to be survivable and redundant. However, there may be some limitations/inoperability to the computer-based radio assets. Handheld and vehicle mounted radios will continue to operate even if the system's backbone is broken. The system's repeaters will continue to operate independently from the main system; therefore, company personnel will be able to maintain a useful level of connection across each area at a minimum. If repeaters are not working, the radios still have line of sight capabilities for direct communications as needed.

7.4.2 Alternate Communication Modes

Government Emergency Telecommunications Service (GETS)	PacifiCorp employees may utilize the Government Emergency Telecommunications Service (GETS), a program that allows us prioritization on busy land-based telephone circuits during emergencies. Most commonly, employees activate GETS and WPS via an application downloaded on their company cell phone. In the absence of the cellular app, GETS and WPS directions can be found at website: Government Emergency Telecommunications Service User Guide (cisa.gov)
Wireless Priority Service (WPS)	Key personnel have also been given access to the additional Wireless Priority Service (WPS), which gives priority on cell towers. WPS is an additional service connected to GETS to which a few employees have access. WPS provides an additional layer of priority for cell phone networks. WPS has an ongoing monthly charge as well as a per-call charge, so it is limited to specific employees at this time. Most commonly, employees activate GETS and WPS via an application downloaded on their company cell phone. In the absence of the cellular app, GETS and WPS directions can be found at website: Government Emergency Telecommunications Service User Guide (cisa.gov)
FirstNet	FirstNet is built with and for first responders, and those who support them, to provide a dedicated cellular network on LTE- Band 14 spectrum and all of AT&Ts commercial bands. This system provides 2.91 million plus square miles of coverage across the U.S. and dedicated assets including a fleet of over 150+ portable cell sites.

7.4.3 Contingency Communication Modes

Satellite Phones	Key facilities & personnel have satellite phones for use when primary phone systems are unavailable. Employees will be fully trained on the use of satellite phones. Instructions and the directory are located in the file *PacifiCorp Satellite Phone Instructions & Directory*.
Starlink	PacifiCorp has multiple Starlink mobile satellite kits that provide data connectivity for up to 128 devices. These kits are mostly utilized by field operations in remote areas but are also deployed as needed during emergency response.

7.4.4 Emergency Communication Modes

Mass Notification Systems	
Alert Media	PacifiCorp utilizes Alert Media for internal notifications and communications to employees regarding emergency response activities such as ECC/DOC activations & meetings. The primary use of this system is to send notifications via text, phone, & email directing people to additional information regarding an upcoming or ongoing incident activation.
LiveSafe	LiveSafe provides a platform for employees to easily submit safety and security information, upload relevant photos or videos, and provide additional details through two-way chat as well as receive emergency notifications and critical safety communications across channels (email, SMS, push notification, and phone call) through broadcast messages.
Additional Emergency Communication Systems	
Amateur radio	PacifiCorp has an HF radio that will allow for communications to other local, state, federal, and private partners through amateur radio bands being utilized by company employees that hold amateur radio licenses.
SHARES HF Radio	The SHAred RESources (SHARES) High Frequency (HF) Radio program provides an additional means for users with a national security and emergency preparedness mission to communicate when landline and cellular communications are unavailable. SHARES members use existing HF radio resources to coordinate and transmit messages needed to perform critical functions, including those areas related to leadership, safety, maintenance of law and order, finance, and public health.
Conference Bridges	Multiple conference bridge lines have been established for immediate conference calling during an incident. Emergency Management and System Operations also has a bridge line established for contingency operations which may be used as needed.

8. INTEGRATED PREPAREDNESS PLAN

8.1 Overview

PacifiCorp's Integrated Preparedness Plan (IPP) is a roadmap to develop and maintain preparedness capabilities for an effective all hazards response in the company's service territory. The IPP involves a coordinated preparedness strategy. This strategy combines enhanced planning, resource acquisition, innovative training, and realistic exercises to strengthen emergency preparedness and response capabilities. The IPP is for internal employees involved in the PacifiCorp emergency response structure and is updated annually.

8.2 Preparedness Priorities

PacifiCorp's current IPP priorities include 1) operational coordination and 2) situational assessment. These priorities are informed by input from internal and external stakeholders, best practices and lessons learned during exercises and real-world events.

8.2.1 Operational Coordination

The operational coordination priority addresses the management and coordination within and among the Pacific Power and Rocky Mountain Power ECCs, DOCs and coordination with local public safety partner's EOCs.

8.2.2 Situational Assessment

The situational assessment capability addresses the company's ECC and DOC ability to collect and deliver enhanced information and decision-relevant information regarding the nature and extent of the hazard, any cascading effects, and the status of the response to executives and internal & external response personnel.

8.3 After Action Reports

By continuously monitoring areas of success and improvement actions, PacifiCorp can regularly examine capabilities to ensure they are sufficient, accurate and effective to handle our relevant threats, hazards, and risks. Successes and areas for improvement identified in prior events and exercises inform future training & exercise activities. After exercises and real-world events an After-Action Report (AAR) process is initiated to document:

- Programs, processes, and training that worked well.
- New ideas or observations that can be captured and evaluated for possible program improvements.
- Issues or areas of improvements to ensure they are vetted and documented.

The AAR process can be implemented after any event where collaborative learning and issue resolution could be beneficial to company personnel, contractors, or customers.

8.4 Training Tracking

Training opportunities are selected through a method that allows an identified target audience to gradually build knowledge and skills to effectively implement certain actions or decisions, as related to the identified priority areas. Following training opportunities are exercise events intended to progressively challenge participants through simulated scenarios that demonstrate current capabilities and potential areas in need of improvement.

PacifiCorp internally tracks training participation and participant training records through its Learning Management System. Individuals are encouraged to track their training records separately.

8.5 Exercise Planning

Exercises and associated training progressively build off each other. Key PacifiCorp personnel participate in a progressive multi-year exercise program involving a series of increasingly complex exercises. Each successive exercise builds upon the previous one until proficiency is achieved.

The Homeland Security Exercise and Evaluation Program (HSEEP) provides best practice guidance for exercise design & development. PacifiCorp references HSEEP recommendations when designing exercise processes and materials.

9. PLAN MAINTENANCE and UPDATE

Facilitated by emergency management, this Emergency Response Plan, the External Coordination and Communication Annex and associated materials will be reviewed and updated annually by key internal stakeholders, including system operations, safety, and joint information team members.

The emergency management staff coordinate revisions and updates of the Plan and its components. The Plan is updated according to the instruction above or in response to a major revision of plan guidance or upon direction from the senior executive staff. Emergency management will review the Plan annually. New policies, best practices, and stakeholder feedback inform each update.

Review/Update	Frequency
Overall Plan	Annually
Roles and Responsibilities	Post-event or post-incident
Action Plans	Post-event or post-incident
Key Position Training	Semiannually
Role Assignments	Annually
Staff Contact Information	Annually
Stakeholder Contact Information	Annually
Energy Emergency Action Plan	Annually or with changes in FERC / WECC requirements and / or internal procedures

10. ANNEX

01 External Emergency Coordination and Communication

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.	Rulemaking 18-12-005 (Filed December 13, 2018)

2025 ANNUAL ACCESS AND FUNCTIONAL NEEDS PLAN OF PACIFICORP (U 901 E)

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Dated: January 31, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.	Rulemaking 18-12-005 (Filed December 13, 2018)

2025 ANNUAL ACCESS AND FUNCTIONAL NEEDS PLAN OF PACIFICORP (U 901 E)

PacifiCorp d/b/a Pacific Power (PacifiCorp or company) submits its plan to address access and functional needs (AFN) customers and communities during a de-energization event, attached as Attachment A. The Company has made efforts to align this plan with the joint investor-owned utility working group AFN Plan template, as appropriate. This plan is submitted consistent with Decision (D.) 21-06-034 issued June 24, 2021, Decision Adopting Phase 3 Revised and Additional Guidelines and Rules for Public Safety Power Shutoffs (Proactive De-Energizations) of Electric Facilities to Mitigate Wildfire Risk caused by utility infrastructure, specifically Appendix A to the Phase 3 Decision (Appendix A), Section K, Reporting.

Dated: January 31, 2025

Respectfully submitted,

/s/

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ATTACHMENT A

PacifiCorp
Plan to Support Populations with Access and Functional Needs During Public Safety Power Shutoffs

January 31, 2025

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EXECUTIVE SUMMARY

During extreme weather conditions, utilities may temporarily turn off power to specific areas to protect the safety of customers and communities, enacting a Public Safety Power Shutoff (PSPS), which continues to be a necessary tool of last resort to prevent our electric system from becoming a source of wildfire ignition. To support individuals with Access and Functional Needs (AFN) during PSPS, each of the Investor-Owned Utilities (IOUs) developed its respective 2025 Annual AFN PSPS Plan ("AFN Plan" or "Plan") with assistance from regional and statewide AFN stakeholders, representing a broad spectrum of expertise. The Plan leverages Federal Emergency Management Administration's (FEMA) Developing and Maintaining Emergency Operations Plans Comprehensive Preparedness Guide 101 Six-Step Process.[1]

The IOUs are committed to addressing the needs of individuals with AFN before, during, and after a PSPS and have established a partnership with the AFN Collaborative Council and the AFN Core Planning Team[2] to seek guidance and address the "Why," "Who," "What," and "How" to better mitigate risk and support individuals with AFN.

PacifiCorp acknowledges and is thankful to the Joint IOUs, AFN Collaborative Council and AFN Core Planning Team for their guidance and commitment in developing the 2025 AFN Plan template.

WHY

As climate conditions change, the threat of wildfires in California continues to grow. One critical tool used to prevent wildfires is the use of PSPS, in which an IOU may temporarily shut off power to a neighborhood during dangerous weather conditions to prevent the electric system from becoming a source of ignition. These safety shutoffs are a measure of last resort for keeping customers and communities safe. A PSPS, although necessary, disrupts the everyday lives of impacted individuals, including those with AFN and/or those who may be electricity dependent, which will be discussed further in this Plan. The purpose of this Plan is to mitigate the impact of PSPS events on individuals with AFN.

[1] For details on how to develop and maintain Emergency Operations Plans, visit: Developing and Maintaining Emergency Operations Plans Comprehensive Preparedness Guide (fema.gov)
[2] See Appendix A for members of the AFN Core Planning Team and Collaborative Council

WHO

The IOUs have made progress in identifying individuals with AFN across their respective service areas, collectively identifying approximately 4 million[3] people in the state through defining, mapping, enabling, and promoting self-identification. In order to support and target individuals that are electricity dependent, the Joint IOU Statewide AFN Advisory Council[4] and AFN Core Planning Team developed a definition of Electricity Dependent Individuals[5] that this Plan seeks to support. That definition remains unchanged from 2022.

Electricity Dependent Definition: Individuals who are at an increased risk of harm to their health, safety, and independence during a PSPS event for reasons including, but not limited to:

- Medical and Non-medical
- Behavioral, Mental and Emotional Health
- Mobility and Movement
- Communication

PacifiCorp understands there is more work to be done and will continue these efforts to identify additional individuals with AFN in 2025.

WHAT & HOW

Working alongside the AFN Collaborative Council and AFN Core Planning Team, PacifiCorp stays informed of the IOU's goals, objectives, and potential opportunities for enhancements in 2025. PacifiCorp continues to monitor and incorporate input from this process. The overarching goal is to mitigate impacts of a PSPS on individuals with AFN, served by PacifiCorp, through improved customer outreach, education, assistance programs and services.

[3] Represents total counts of AFN designations in each of the IOU's database not unique individuals or accounts.
[4] See Appendix A for a list of the members of the Joint IOU Statewide AFN Advisory Council.
[5] IOUs will strive to implement this proposed definition contingent on operational feasibility and in alignment with AFN identification requirements with the CPUC's PSPS decisions. The IOUs will continue to collaborate with AFN stakeholders to refine this definition as appropriate.

1. INTRODUCTION

In accordance with the California Public Utilities Commission (Commission or CPUC) Decision (D.) 21-06-034 Guidelines issued in Phase 3 of Rulemaking 18-12-005 (Phase 3 PSPS Decision) and using the Six-Step Planning Process in the Federal Emergency Management Agency's (FEMA) Developing and Maintaining Emergency Operations Plans Comprehensive Preparedness Guide 101, the Joint IOUs worked collaboratively with the AFN Core Planning Team to implement the "Whole Community"[6] approach to develop an overarching Joint IOU statewide strategy to meet the diverse needs of individuals with AFN.

Each California IOU will file their respective 2025 AFN Plans with the CPUC by January 31, detailing their programs to support people and communities with AFN before, during, and after a PSPS. The IOUs will provide the CPUC with quarterly updates regarding progress toward meeting the established objectives and the impact of their efforts to address this population before, during, and after PSPS, while optimizing opportunities for consistency where possible.

1.1 Subject Matter Experts

According to FEMA Step 1: Engaging the Whole Community in the Planning — Engaging in community-based planning, planning that is for the whole community and involves the whole community, is crucial to the success of any plan.

On September 17, 2024, the IOUs introduced this effort at the broader Q3 Joint IOU Statewide AFN Advisory Council meeting, invited participation, and subsequently held a kick-off meeting with Core Planning Team[7] members on October 23, 2024. The 2025 AFN Core Planning Team comprises eight organizations representing the diverse needs of the AFN community.

[6] Whole Community approach as defined by FEMA, refers to preparedness as a shared responsibility and involvement of everyone, including but not limited to individuals and families with access and functional needs. Complete definition available at www.fema.gov/about/glossary (scroll down to "Whole Community").
[7] See Appendix A.

Table 1 below reflects the organizations involved in the development of the 2025 AFN Plan.

Table 1. Engaging the Whole Community

Planning Group	Participants/Stakeholders
AFN Collaborative Council (per the Phase 3 PSPS Decision):	California Foundation for Independent Living Centers (CFILC)
	California Health & Human Services (CHHS)
	California Office of Emergency Services (Cal OES)
	Disability Rights California (DRC)
	Disability Rights Education & Defense Fund (DREDF)
	State Council on Developmental Disabilities (SCDD)
	2-1-1[8]
AFN Core Planning Team	Department of Developmental Services
	Disability Policy Consultant
	Inland Regional Center
	PacifiCorp
	Redwood Coast Regional Center
	San Diego Regional Center
	San Gabriel/ Pomona Regional Center
	Tri-Counties Regional Center
Joint IOUs	San Diego Gas & Electric (SDG&E)
	Southern California Edison (SCE)
	Pacific Gas & Electric (PG&E)

As a key component to engaging the Whole Community in planning, the IOUs will continue to solicit feedback from the AFN Collaborative Council, the Joint IOU Statewide AFN Advisory Council, each utility's respective Regional PSPS Working Groups and other regional and statewide AFN experts such as community-based organizations (CBOs), healthcare partners, representatives of durable medical equipment, and local government agencies. These groups serve as thought leaders and offer insight, feedback, and input on each IOUs' customer outreach strategy, programs, and priorities. The IOUs seek to conduct regular meetings to actively identify issues, opportunities, and challenges related to the IOUs' ability to mitigate the impacts of wildfire safety strategies, namely PSPS.

[8] Although 2-1-1 was not required per the Phase 3 PSPS Decision, they have been invited to join the AFN Collaborative Council.

The planning process presented herein provides opportunities to collect feedback and implement strategic improvements with details included in specific IOU plans. The Joint IOUs continue to look at expansion of program offerings, refresh the Joint IOU statewide PSPS Preparedness website, www.PrepareForPowerDown.com, conduct outreach and education, as well as expand access to eligible populations. PacifiCorp continues to learn from these efforts and best practices set forth by the Joint IOUs.

1.2 Purpose, Scope, Situational Overview and Assumptions

1.2.1 Purpose/Background — WHY

The Plan focuses on mitigating the impacts of PSPS for individuals with AFN. The IOUs intend to build on this Plan and strive for continuous improvement based on insights from the experts and feedback channels outlined in this plan. Each IOU's respective 2025 AFN Plan addresses the following:

- Who the IOUs need to communicate with
- What resources and services are needed during PSPS
- How the IOUs communicate with individuals with AFN
- How the IOUs make resources and services available to individuals with AFN

1.2.2 Scope — WHO

The Joint IOUs and the CPUC recognize the definition of AFN as defined by the California Government Code §8593.3: "individuals who have developmental disabilities, physical disabilities, chronic conditions, injuries, limited English proficiencies, who are non-English speaking, older adults, children, people living in institutional settings, or those who are low income, homeless, or transportation disadvantaged, including but not limited to, those who are dependent on public transit and those who are pregnant."

Acknowledging that the California Government Code definition of AFN is broad, the CPUC authorized the IOUs to follow the FEMA 6-Step Process by engaging the Whole Community through the Joint IOU Statewide AFN Advisory Council to create a common definition of "Electricity Dependent." Therefore, the IOUs use this common definition to help inform new enhancements to programs and resources currently available.

Electricity Dependent: Individuals who are at an increased risk of harm to their health, safety, and independence during a Public Safety Power Shutoff, for reasons including, but not limited to:

- Medical and Non-medical
- Behavioral, Mental and Emotional Health
- Mobility and Movement
- Communication

Examples of Electricity Dependent include, but are not limited to:

- **Medical and Non-medical:**
    - Respiratory equipment: oxygen, respirator, inhalation therapy, apnea monitoring, suction machines, airway clearance, Airway Clearances Vests, cough assistive devices, hemodialysis
    - Nutritional equipment: gastric feed tube, specialized diet meal preparation equipment (e.g., feeding pumps, blenders)
    - Heating/cooling equipment: refrigeration, body temperature regulation
- **Behavioral, Mental, and Emotional Health:**
    - Powered equipment supporting regulation of emotional behaviors (e.g., sensory lights)
- **Mobility and Movement:**
    - Positioning equipment: Lift, mobility tracking system, power wheelchairs and mobility scooters, in home chair lift, electric bed
- **Communication:**
    - Augmentative communication devices (e.g., tablets, wearables, eye gaze), alert systems
    - Powered equipment for hearing or vision support (e.g., alert systems)

1.2.3 Situational Overview

According to FEMA Step 2: Understand the Situation — Understanding the consequences of a potential incident requires gathering information about the potential AFN of residents within the community.

The phrase "Understand the Situation" continues with identifying risks and hazards. The assessment helps a planning team decide which hazards or threats merit special attention, what actions must be planned for, and the resources likely to be needed.

The Core Planning Team has identified the following key risks of PSPS:

- Individuals with AFN are unable to use power for devices or equipment for health, safety, and independence due to a PSPS.

During the planning process, the AFN Core Planning Team emphasized that the needs of individuals with AFN extend well beyond medical devices alone and that the risks are as diverse as the population. The IOUs recognize that the impacts of a PSPS are dynamic and are committed to supporting customers before, during and after a PSPS.

AFN Population and Identification

PacifiCorp has made progress and continues to seek improvements to identifying AFN individuals who are electricity dependent through program enrollments and enabling more customers to self-identify. PacifiCorp identifies the following customers as AFN in the company's customer service system:

- Customers enrolled in the following programs:
    - Medical Certification
    - Medical Baseline (MBL), including Life-Support (Critical Care)
- Customers who self-identify
    - As having a medical condition
    - As having an AFN

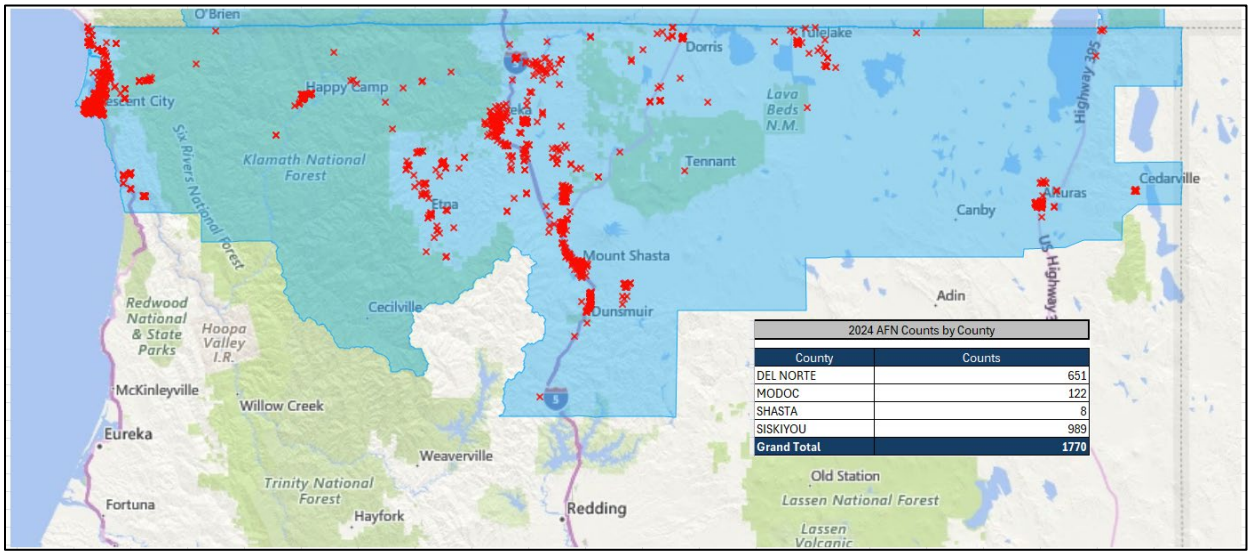
Table 2 below accounts for the number of customers identified as AFN in PacifiCorp's service territory.

Table 2. PacifiCorp's Customers with Access and Functional Needs

Customers with Medical Certificates and/or MBL	Customers self-identified as having a medical condition or other AFN (Beyond medical certificates and MBL)	Percentage of Customers Identified as AFN Based on Total Residential Customer Base
133	1637	4.82%

PacifiCorp's AFN density map shown in Figure 1 allows the Company to quickly identify geographic areas that have larger populations of AFN customers. This map enables PacifiCorp to strategically allocate resources by geography such as staffing a community resource center for customers experiencing a PSPS.

Figure 1. Service Area Map of PacifiCorp Customers with AFN



1.2.4 Planning Assumptions

Below are the initial planning assumptions used to develop the annual AFN Plan:

- For PSPS, every effort is made to provide notification in advance of power shutoff
- Effective support of individuals with AFN requires a Whole Community[9] approach (e.g., utilities, CBOs, non-profits organizations, government agencies)
- PSPS may occur concurrently with unrelated emergencies (e.g., active wildfires, earthquake, cyber-attacks, technological hazard incidents)
- The scope of PSPS can increase or decrease as weather conditions are monitored across the service area

1.3 Operational Priorities – WHAT

According to FEMA Step 3: Operational Priorities – specifying what the responding organizations are to accomplish to achieve a desired end-state for the operation.

The goal of the AFN Plan is to mitigate the impacts of PSPS on individuals with AFN served by the IOUs through improved customer outreach, education, assistance programs and services. PacifiCorp will continue its commitment to mitigating impacts of PSPS by focusing on key objectives identified through the 2025 planning meetings: Progress will be reported out in the quarterly updates submitted to the CPUC.

2025 Key Objectives:

- Increase awareness of IOU programs and services available before, during, and after a PSPS activation
- Continue to identify individuals who are Electricity Dependent
- Identify enhancements to programs and resources needed to mitigate the impacts of PSPS
- Coordinate and integrate resources with state, community and utility to minimize duplication

[9] The term "Whole Community" refers to the concept as discussed in the FEMA Six Step Comprehensive Preparedness Guide.

1.4 Plan Development

According to FEMA Step 4: Plan Development – Develop and Analyze Courses of Action – This step is a process of generating, comparing, and selecting possible solutions for achieving the goals and objectives identified in Step 3.

The IOUs have worked to deliver consistent services and resource offerings; however, the delivery and eligibility are likely to differ by service area. Proposed recommendations to meet the Key Objectives for 2025:

Increase awareness of our programs and services available before, during and after a PSPS

- Increase awareness among PacifiCorp's Wildfire Advisory Board (Board) members via presentations/materials
- Engage with the Board, CBOs, health care coalitions and other local AFN service providers to identify opportunities to amplify AFN program messaging
- Explore making appropriate updates to PSPS materials to reflect the needs of individuals with AFN

Continue to identify individuals who are Electricity Dependent

- Enhance existing marketing and outreach campaigns based on data and feedback received through surveys and interviews
- Continue to work with CBOs, Regional Centers and healthcare organizations to ensure their clients are informed about available PSPS resources
- Partner with Wildfire Advisory Board members and other AFN service providers to better understand the needs of AFN customers and gaps in PacifiCorp's current offerings

Identify new enhancements to programs and resources needed to mitigate the impacts of PSPS

- Continue to review customer feedback from PSPS survey results, including CRC survey results, to benchmark and evaluate if programmatic changes are needed to enhance existing resources and support

Coordinate and integrate resources with state, community, utility to minimize duplication

- Identify opportunities and efficiencies to ease Medical Baseline (MBL) program enrollment in accordance with CPUC and legislative framework

1.5 Plan Preparation and Review

According to FEMA Step 5: Plan Preparation, Review, and Approval – This step is a process of preparing the document and getting it ready for implementation.

Each IOU will file their respective 2025 AFN Plans with the CPUC by January 31, detailing its programs to support individuals and communities with AFN before, during, and after PSPS.

PacifiCorp continues to use the Joint IOU template, maintaining consistency with that template where possible.

1.6 Plan Implementation

According to FEMA Step 6: Implement and Maintain the Plan – This step is the final step which is an ongoing process of training personnel to perform tasks identified in the plan, exercising, and evaluating plan effectiveness, and revising and maintaining the plan.

Upon filing the AFN plan, each IOU will implement new and maintain existing goals and objectives as specified in the Plan. Additionally, the IOUs will continue to provide quarterly updates on progress made.

1.7 Research and Surveys

In 2025, the IOUs will continue to collaborate and share best practices as they solicit feedback about PSPS resources offered to individuals with AFN through a variety of channels, including consultation with various advisory groups.

PacifiCorp will continue to solicit feedback from working groups, local governments, tribes, and critical facilities; webinars for customers and communities; wildfire and PSPS awareness studies; feedback via digital channels; PSPS Tabletop Exercises; and notification message testing.

PacifiCorp conducts two rounds of surveys and interviews each year to assess the company's wildfire safety communication campaigns. Survey results are utilized to assess the key performance indicators described in Section 1.8 Success Measures and Metrics. Survey and interview results are located in Appendix D.

As a result of feedback and research from CBOs, local governments, and tribes who support AFN populations, the IOUs are committed to continuously reviewing the needs of individuals with AFN before, during, and after PSPS. This thorough review allows the IOUs to enhance support for individuals who rely on electricity to maintain necessary life functions, including those who utilize durable medical equipment and assistive technology.

1.8 Success Measures and Metrics

In 2025, PacifiCorp will continue to use the Key Performance Indicators (KPIs) initially developed with the AFN Core Planning Team for the 2022 AFN Plan. These KPIs seek to measure the impacts of PSPS on individuals with AFN, awareness of support programs, and satisfaction of services offered during a PSPS. The most recent pre- and post- season survey results that address the KPIs can be found in Appendix D of this report.

Key Performance Indicators:

1. The percentage of individuals with AFN who were aware of what support and resources were available to them during a PSPS
2. The percentage of individuals with AFN who were able to use necessary medical equipment to maintain necessary life functions for the duration of any PSPS that affected them
3. The percentage of individuals who used mitigation services (e.g. CRCs, backup power programs) and reported satisfaction with the level of support received

While Section one is a high-level overview of the IOUs' shared vision, the details of PacifiCorp's AFN Plan can be found in Sections two through five of this Plan. PacifiCorp will continue to remain informed of lessons and best practices identified across the IOUs and strive to improve AFN support where services and partnerships are available.

2. CONCEPT OF OPERATIONS - HOW

This concept of operations describes PacifiCorp's approach to supporting customers with access and functional needs before (preparedness), during (response) and after (recovery) a PSPS.

2.1 Preparedness/Readiness (Before Power Shutoff)

PacifiCorp's AFN customers can access information on wildfire preparedness and programs through communication campaigns, outreach, personal contact and when an event is forecasted, in real-time on the Company's website.[10] All customers have access to the Company's online webinars, events, and preparedness information to ensure that any non-identified AFN customers have an opportunity to access resources. PacifiCorp's AFN and wildfire programs are identified below. In 2025, the Company will continue its commitment to providing programs and services that are easily accessible to customers.

2.1.1 AFN Identification

PacifiCorp understands the importance of identifying customers with AFN through a variety of channels. Customer service representatives are trained to listen for key words during phone conversations which trigger them to ensure whether it is appropriate for the customer account to have an AFN designation. When a customer identifies as having AFN, the customer service representative will flag the customer's account and will share information about AFN programs for which the customer may be eligible.

In 2021, PacifiCorp added a check box on the California Alternate Rates for Energy (CARE) application for customers to self-identify as AFN. Due to the update to the CARE applications, an additional 997 customers have self-identified as AFN. In 2024 alone, PacifiCorp saw an additional 527 newly identified AFN customers via the CARE application and an overall increase of 127% since the modification of the CARE application in 2021. The increase in enrollments though this channel demonstrates that updates to the Company's CARE application have - and will likely continue to have - positive results. From 2023 to 2024, the Company had a 42% increase in AFN customers.

PacifiCorp recognizes the importance of continuing to identify customers with medical baseline and other AFN. In 2025, PacifiCorp will expand its self-identification outreach campaign through updated marketing materials, website enhancements and targeted outreach to AFN customers through regional centers, Tribal partners, healthcare organizations and other AFN service providers.

[10] https://www.pacificpower.net/outages-safety/wildfire-safety/public-safety-power-shutoff.html

2.1.2 Backup power programs

Portable Battery and Backup Electric Power Generator Rebate Programs[11]

PacifiCorp offers a backup electric power rebate for residential customers in its California service territory. All residential customers are eligible to claim a rebate of up to $300 for the purchase of a backup power supply and customers enrolled in the Medical Certificate or California Medical Baseline Program are eligible to claim a rebate of up to $800. Items approved for the rebate program include portable batteries, power stations, and gasoline generator options. Tenants and property owners are eligible to claim a rebate. To date, 706 customers have received rebates.

In 2025, PacifiCorp will review the Backup Electric Power – Generator Rebate Program's webpage for improvements to streamline information and increase accessibility. In addition, PacifiCorp will coordinate with the Board, CBOs, healthcare organizations and other AFN service providers to identify opportunities to amplify and broaden messaging about the Company's backup power programs.

Free Portable Battery Program

PacifiCorp offers free portable batteries to customers receiving the California Alternate Rates for Energy (CARE) and those enrolled in the Baseline Program. The program includes contracted services to provide comprehensive customer outreach, a backup power needs assessment, and delivery and setup of portable batteries. As part of delivery and setup, program participants receive individual education about proper use and maintenance of their device, and ongoing remote technical support as needed. A total of 94 medical baseline customers have received a portable battery to-date.

In 2025, PacifiCorp will review the Backup Electric Power – Free Portable Battery Program's webpage for improvements to streamline information and increase accessibility. In addition, PacifiCorp will coordinate with the Board, CBOs, healthcare organizations and other AFN service providers to identify opportunities to amplify messaging about the Company's backup power programs.

[11] See PacifiCorp back up electric power website for more information, https://www.pacificpower.net/outages-safety/storm-emergency-preparedness/backup-generators.html

2.1.3 Resiliency Programs

PacifiCorp previously offered a grant program to communities seeking to enhance emergency preparedness with renewable generators and energy storage. This program has ended, and funds have been exhausted. A final report on resiliency efforts was submitted via Advice Letter 690-E on August 11, 2022, which contains a more detailed account of the program summarized below.

- No applications were received for portable renewable generators.
- Five technical studies were developed for critical facilities interested in learning more about the costs and benefits of increased on-site resiliency.
- Three critical facilities have been approved to receive grant funding for energy storage projects. As of January 31, 2023, two of those projects completed installation and have been awarded funding.
- The Yurok Tribe is the third and final applicant. A grant will formally be awarded upon completion of project construction and commissioning.

2.1.4 Customer Assistance Programs

Financial Assistance Programs

Medical Baseline (MBL) Allowance Program
PacifiCorp's MBL program helps customers who have additional energy needs for qualifying medical conditions. Qualifying residential customers receive a lower rate baseline allowance on their monthly energy bill. Customers in the MBL program are designated as AFN customers and receive additional notifications when possible, during PSPS events, and may be eligible for additional backup power program offerings.

California Alternate Rates for Energy (CARE) Program

PacifiCorp offers income-qualifying residential customers a 25% discount on monthly bills through the CARE program.

Low-Income Home Energy Assistance Program (LIHEAP)

PacifiCorp customers in low-income households may receive assistance with home energy costs. LIHEAP is administered by the California Department of Community Service and Development through local agencies.

Energy Assistance (ESA) Program

PacifiCorp partners with local community-based organizations to provide energy-saving improvements at no cost to income-qualifying homeowners and renters living in single-family homes, mobile homes or apartments.

Project HELP

PacifiCorp customers may be eligible for support through Project HELP, a nonprofit program administrated by The Salvation Army.

Additional Assistance Programs

Medical Certificates

PacifiCorp residential customers with a serious health condition that (1) could be aggravated by a loss of power in their home or (2) require electricity powered medical equipment in the home, can enroll in the medical certificate program to receive additional notifications when possible during PSPS events, and may be eligible for a baseline allowance at a lower rate and additional backup power opportunities. PacifiCorp's medical certificate online application is available in English and Spanish.

Gift Payment

PacifiCorp provides family and friends the opportunity to make a payment for a customer who may need assistance in paying their electric bill.

Equal Pay

PacifiCorp offers customers the option of paying the same amount each month, based on the average of the last 12 months of billing, allowing for easier budgeting and leveling out seasonal highs and lows.

2.1.5 Emergency Coordination Center

PacifiCorp has established an Emergency Coordination Center (ECC) following the National Incident Management System (NIMS) guidance. ECC staff is available to support all hazardous responses, including PSPS events.

The ECC plays a vital role in monitoring and verifying AFN customers are contacted throughout a PSPS event. AFN customers impacted by a PSPS are identified through a Geographic Information System customer list which is provided to the Company's customer service group and the ECC Executive. Customer service is responsible for providing PSPS notifications to all customers, and additional notifications to AFN customers. During each ECC meeting, customer service provides a status update on notifications and may escalate unmet needs of AFN customers to the ECC Executive to determine if additional action by the Company or local emergency management is required.

With the addition of an AFN Program Manager in 2024, a new AFN Coordinator position was established in the ECC. The AFN Coordinator coordinates with customer service, the Joint Information Team and the ECC Liaison to quickly relay and address unmet needs of AFN customers with local public safety partners. In 2025, PacifiCorp will seek opportunities to further develop the ECC AFN Coordinator role.

The ECC process is reviewed and submitted to the CPUC annually in the General Order 166 (GO 166) report. The April 2025 GO 166 Update will include how the ECC AFN Coordinator is integrated into the Company's incident management framework.

2.1.6 Training and Exercise

PacifiCorp conducts annual PSPS exercises utilizing a whole community approach. The training standards are being developed with other California IOUs and the California Office of Emergency Services, utilizing National Incident Management System (NIMS) courses. During exercise planning, emergency management agencies from tribal, state, county and local jurisdictions, community-based organizations, public health agencies, and any other potentially affected agency, are invited. PacifiCorp's annual PSPS exercises include components that test the Company's protocols related to access and functional needs during extended power outages, including notification processes.

PacifiCorp continues to enhance and expand the training program for ECC staff. Beginning in 2025, all ECC personnel are assigned to complete the following FEMA trainings:

- IS-100 Introduction to the Incident Command System
- IS-200 Basic Incident Command System for Initial Response
- IS-700 An Introduction to the National Incident Management System
- IS-800 An Introduction to the National Response Framework
- All-hazards specific training for each position

Additional training may be assigned for specialized positions based on decision making authority.

2.1.7 PSPS Preparedness Outreach and Community Engagement

Dissemination of timely, accurate, accessible, and actionable information to the public is important in all phases of PacifiCorp's incident management. Communication efforts are listed in the Company's Wildfire Mitigation Plan and Emergency Response Plan which describe the Company's communication and notification processes with public and partner organizations throughout the preparation, response, and restoration cycle. Communication with AFN customers and external partners as early as possible is essential. The PacifiCorp Joint Information Team has established processes and tools to facilitate communication with customers, the public, news organizations, government entities and other external stakeholders through social media, the Company's website, press releases and notification protocols to ensure consistent and comprehensive messaging.

PacifiCorp may continue to refine these communications processes in 2025, building off feedback and lessons learned during trainings, exercises, real world events, advisory groups, customer surveys and partner interviews.

PacifiCorp Wildfire Advisory Board

In addition to participating in the Joint IOUs' advisory and planning efforts, PacifiCorp established a Wildfire Advisory Board (Board) in 2021 to provide direct feedback on the Company's Wildfire Mitigation Plan, PSPS Playbook, Community Resource Center Playbook and Access and Functional Needs Plan. The Board consists of public safety partners, local government representatives, tribal officials, community-based organizations and a representative from the AFN community. See Appendix A for a list of Board members in 2024. Recommendations from the Board inform improvements to the PSPS program.

The Board met in March of 2024, pre-wildfire season, and November of 2024, post-wildfire season. Topics of discussion included systemwide improvements, PSPS history and risk, review of the previous fire season and preparation for the upcoming fire season, the PSPS program, organizational updates, and customer program updates. During the March 2024 meeting, the Board reviewed and provided feedback on updates to the PSPS Playbook and the Emergency Response Plan. Recommendations made by the Board at the November 2024 meeting informed the AFN outreach priorities for 2025; strategies to engage a wider range of local organizations and AFN perspectives on the Board; and priority topics for 2025 meetings including increased engagement with Tribal nations and the Company's efforts to minimize outages. In 2025, PacifiCorp will continue to seek broader perspectives and AFN representation on the Board.

AFN Program Manager

In 2024, PacifiCorp created and staffed an Access and Functional Needs program Manager role that resides within the emergency management team and oversees the development of an integrated access and functional needs program. The AFN program manager participated in the 2024 Statewide AFN Joint IOU meetings and the 2025 AFN Plan Working Group. Additionally, in 2024, PacifiCorp initiated monthly AFN coordination meetings with the California Small and Multi-Jurisdictional Utilities (SMJUs). In 2025, the AFN Program Manager will continue review of existing AFN programs to identify areas for improvement; convene the Wildfire Advisory Board; continue to engage with the Joint IOUs and SMJUs; and seek opportunities to expand relationships and outreach with CBOs, healthcare organizations and other AFN service providers.

AFN Public Education and Outreach

PacifiCorp provides additional PSPS notifications to individuals who have self-identified as having an access or functional need, including medical and medical baseline customers. Having key messages across several communications channels and materials asking AFN customers to self-identify with the company is a vital component to the Company's community engagement and customer outreach strategy.

PacifiCorp has engaged a vendor to survey customers to help inform the Company's communication and education plan, including a strategy which can be tailored for AFN customer outreach and engagement. This includes assessing the need and type of communication channels for people with AFN who may not be able to use standard forms of communication. Survey data has informed the overall outreach strategy, and the company has adjusted and expanded where key messages are disseminated to increase AFN self-identification.

PacifiCorp will continue to provide information about the PSPS notification process, how to prepare for outages, the Company's backup power programs and benefits of AFN self-identification. In 2025, PacifiCorp's AFN outreach efforts will focus on amplifying messaging about AFN program offerings and removing barriers to accessing the Company's AFN programs, with the ultimate goal of increasing the number of customers who self-identify as being electricity dependent or having an AFN. Outreach tactics under consideration have been informed by customer survey findings, partner interviews, Wildfire Advisory Board feedback, and direct feedback from CBOs and other AFN service providers. Upon completion, new and updated materials will be distributed through CBOs, other AFN service providers and public safety partners.

PacifiCorp's PSPS AFN outreach plan for 2025 is shown in Table 3 below.

Table 3. 2025 AFN PSPS Outreach Tactics and Initiatives

Outreach tactic	2025 initiatives
Wildfire Advisory Board	PacifiCorp will continue to convene the Board to share PSPS information and to seek guidance on local outreach opportunities. New: PacifiCorp will seek additional members to join the Board, with a focus on a wider range of service providers for AFN communities and AFN representation.
AFN Programs Toolkit	New: PacifiCorp will develop an AFN programs toolkit for external partners, including flyers and copy for partner websites and social media.
Website	PacifiCorp will continue to maintain the Company's PSPS websites. New: PacifiCorp will review the Company's website related to programs and offerings supporting AFN customers, for opportunities to enhance accessibility and ease of use. New: PacifiCorp will develop a one-stop-shop webpage for AFN customers to easily access information and programs.
Social media	PacifiCorp will continue to post content to social media sites and attempt to provide information in English and Spanish during a PSPS.
Tribal Engagement	PacifiCorp will continue to coordinate with Tribal partners on engagement opportunities. New: PacifiCorp will seek opportunities to post information about wildfire safety and PSPS in Tribal publications, including information about AFN programs.
Collateral	PacifiCorp will continue to publish and distribute PSPS informational brochures. New: PacifiCorp will develop a simplified AFN program flyer in English and Spanish.
Customer E-mail	Before wildfire season, PacifiCorp will continue to e-mail PSPS information to all customers. New: PacifiCorp will conduct a targeted e-mail campaign to AFN customers about available programs prior to wildfire season.
Bill messages	Before and during wildfire season, PacifiCorp will continue to send on-bill messages about wildfire safety and preparedness.

Accessible Communications

Pre-fire season, PacifiCorp enhances online customer communications through the website, customer notification emails, social media, wildfire webinars and in partnership with community-based organizations, Tribal Authorities, local governments, regional centers and other service providers to amplify reach to customers. PacifiCorp's website provides digital brochures and handouts on the Company's backup power programs, wildfire preparedness, and the medical baseline program.

In 2024, PacifiCorp hired a new Wildfire Mitigation Communications Program Manager. This position plays a pivotal role in ensuring PSPS, wildfire mitigation and wildfire response information is accessible. In March 2023, PacifiCorp added an online Medical Certification form in Spanish to its website to enhance ease of communication for customers. As of July 2024, PacifiCorp's Spanish wildfire page content mirrors that of the website's English content, offering a one-to-one certified translation. Handouts about medical programs are available digitally in English, Spanish and Hmong, and in hard copy in English and Spanish.

PacifiCorp's customer service agents have access to and training with wildfire safety, preparedness and PSPS-related communications and can facilitate a conversation between the customer and translation service to ensure customers can receive wildfire safety and preparedness and PSPS-related information they need. Information about AFN programs is available through customer service in over 300 languages including Chinese traditional, Chinese simplified, Tagalog, Vietnamese, Mixteco, Zapoteco, Hmong, German, and Spanish.

In 2025, the Company will review and update online messaging about AFN programs to promote accessibility and ease of use. A new one-stop-shop webpage for AFN related programs will be developed to provide easier online navigation for customers. Additional webpages and collateral will be translated.

Tribal Engagement

A significant portion of the Karuk Tribe's offices and lands are in a high fire consequence area of Siskiyou County. Representatives from the Tribe are invited to participate and are standing members in the PacifiCorp Wildfire Advisory Board. PacifiCorp's regional business manager conducts regular calls with the Tribe's leadership to quickly address any issues as they arise and to discuss PacifiCorp's operations in the area including wildfire mitigation and PSPS.

In 2023, the Company hired a Tribal Liaison Representative who provides internal guidance and support to staff who work with Tribes or are seeking partnership with Tribes in PacifiCorp service territories. The Tribal Liaison also supports understanding of cultural needs and protocols for Indigenous customers who have indicated that have an AFN.

As part of the Company's efforts to hear from a variety of stakeholders and partners, PacifiCorp interviewed a representative from the Karuk Community Center in 2021 and the Karuk Tribe's Emergency Manager in 2023 during the semi-annual survey. In 2024, PacifiCorp interviewed members of the Tolowa Dee-ni' Nation - Smith River Tribe for additional Tribal perspectives on the Company's PSPS program. See the *CBO and Partner Interviews* section below and Appendix D for more information.

In coordination with the Company's Tribal Liaison Representative, PacifiCorp will continue to foster relationships with Tribal leaders and staff and explore additional collaboration opportunities with the Karuk and Yurok Tribes who have served on the Wildfire Advisory Board. Additionally, PacifiCorp will work to extend our outreach with some of the other Tribes and Rancherias in the Company's service territory in California.

CBO Outreach

PacifiCorp coordinates with community-based organizations, healthcare organizations and other AFN service providers to amplify messaging about the Company's AFN programs via partner websites, social media and flyer distribution at outreach events, and direct distribution from case worker to client. In 2024, PacifiCorp developed copy in English and Spanish for external partners to post on their websites and social media.

PacifiCorp partners with Great Northern Services in Weed, the Karuk Tribe Community Center in Happy Camp, the Redwood Coast Regional Center and Far Northern Regional Center in addition to coordinating with the 23 Wildfire Advisory Board members (identified in Appendix A of this report) on outreach opportunities.

Between July and December 2024, PacifiCorp conducted targeted outreach to the following organizations:

- Del Norte County Health and Human Services
- Del Norte County Communications and Equity
- Del Norte and Tribal Lands (DNATL) Community Food Council
- Family Resource Center of the Redwoods
- Siskiyou County Health and Human Services
- Siskiyou County Health Care Coalition
    - Fairchild and Mercy Medical Centers
    - Sierra – Sacramento Valley Regional Disaster Medical Health System
    - State & Local Public Health
    - Siskiyou County Environmental Health, Behavioral Health, Office of Education
    - Trinity County Health Care Coalition
    - Planning and Service Area 2 Agency on Aging (Modoc, Shasta, Siskiyou)
    - NorCal Continuum of Care/Homeless Coalition (Modoc, Shasta, Siskiyou, Del Norte)
    - Mt. Shasta
    - State & Local OES
    - EMS Providers
    - Fire Chief's Association
- Tri-County Independent Living
- 2-1-1 NorCal

The Company is seeking additional messaging avenues outside of its currently defined outreach strategy. This involves working with community partners to find appropriate places and spaces to add AFN-specific messages to existing platforms such as CBO emails, webpages and/or social media pages. This work is ongoing and is carried out by the Company's regional business managers who collaborate closely with their community stakeholders and through direct outreach to community organizations by, the Access and Functional Needs Program Manager and emergency management personnel. When AFN outreach materials are updated in 2025, PacifiCorp will coordinate with these organizations to share the information with their communities.

Customer Surveys

In 2024, PacifiCorp conducted two annual surveys, one pre- and one post-fire season. MDC Research has been contracted to collect data from customers and to conduct interviews with CBOs and other community partners. The goal is to evaluate the impact of the Company's communication campaigns, receive direct feedback from community partners on outreach, support, and process improvements, and to collect demographic information about our customers. In March and November 2024, a total of 1,170 surveys were completed: 1,010 web and 160 phone. A comprehensive report on the Company's 2024 survey results is located in Appendix D. Findings from the 2024 research will inform PacifiCorp's messaging and outreach initiatives in 2025, including, but not limited to: amplifying messaging about the Company's AFN programs; translating additional AFN program materials into Spanish; and enhanced coordination with local CBOs and other AFN partners. In 2025, PacifiCorp will review the survey for areas of improvement specific to AFN customer needs.

CBO and Partner Interviews

MDC Research also conducted in-depth interviews with CBOs and other partners in PacifiCorp's California service area in March and November 2024. Partners included the Tolowa Dee-ni' Nation- Smith River Tribe, Family Resource Center of the Redwoods, Siskiyou Fairgrounds, Del Norte County Office of Emergency Management, and the Yreka Area Fire Safe Council. The interviews lasted 30 minutes and were conducted virtually. Findings from the 2024 partner interviews will inform PacifiCorp's outreach tactics in 2025.

2.2 PSPS Activation (During – Emergency Coordination Center activation)

2.2.1 PSPS Communications

All Customers

PacifiCorp's Public Safety Power Shutoff event communication and notification plan has two primary systems. First, direct communications, through pre-identified channels are used to provide detailed notices to key stakeholders, namely public safety partners and critical facilities and critical infrastructure. Second, a series of automated notices (e-mail, text, and direct phone calls) to customers, together with published information on the Company's website, social media channels, and proactive media outreach, are employed to provide notice to the public at the primary stages of the PSPS process, including at a minimum for pre-activation, activation and re-energization. The communication and notification plan are exercised annually, as part of the PSPS tabletop and functional exercises, and refined as appropriate.

AFN Customers

When a PSPS event is forecasted, a list of impacted customers is extracted from the Customer Service System where AFN customers are identified, and customer service staff attempt to make personal phone calls to each customer. To the extent possible, PacifiCorp sectionalizes circuits into smaller zones for de-energization in order to minimize customer impacts, and subsequently, the number of AFN customers de-energized. This approach helps PacifiCorp to personally reach out to AFN customers. Contact occurs prior to an event, at the beginning of re-energization, and after energization is completed. Customer service tracks if a positive confirmation of contact was made with medical baseline (MBL) and AFN customers. The results of the contact are reported to the ECC Executive.

If an AFN customer needs additional assistance, the AFN Coordinator coordinates with customer service, the ECC Joint Information Team and the ECC Liaison to quickly relay the information to local public safety partners. Such coordination may lead to a wellness check.

2.2.2 Website

To ensure that the public can access timely and detailed information about both potential and actual PSPS events relevant to a particular location, PacifiCorp has modified its main PSPS webpage, available at www.pacificpower.net/psps. The web-based tool allows members of the public to enter an address into a search bar to determine in real-time, if that address is in an area which may be subject to a PSPS.

An additional online tool is available for members of the public to see the "Public safety power shutoff forecasting" for that area over the following week. The status indicates and defines whether the area is operating as "Normal," whether there is a PSPS "Watch," or whether there is an actual PSPS "Event."

PacifiCorp's Weather Awareness Websites received numerous enhancements in 2024 in order to meet two goals for both customers and PacifiCorp's operations and leadership teams: to better serve as a weather-related decision-support platform, and to better deliver local weather information. These improvements include the ability for PacifiCorp's meteorology team to access additional fire metrics at a more granular level. Additional mapping tools and weather variables were added to increase forecasting data and situational awareness ability across the service territory. PacifiCorp's website performed well during the September 2020 windstorm event where a significant surge in website visits enabled +/- 200,000 visitors and more than 1.6 million web page views. This event demonstrated capable broadband performance.

2.2.3 Public Safety Partner Portal

PacifiCorp has developed a Public Safety Partner Portal, a secure web-based application that hosts information about customers identified as critical facilities or infrastructure. Key information includes location, primary/secondary contact information, backup generation capabilities and more. The portal is accessible to approved partners during PSPS events to increase transparency, consistent information-sharing and overall awareness of potentially affected facilities. Public safety partners with access include emergency responders from federal, state, local and tribal governments, telecommunication providers, water agencies, public-owned utilities, emergency hospitals, and transportation agencies. The portal also helps PacifiCorp prioritize restoration, backup power evaluation, additional communications, and other resources before and during PSPS events to critical facility customers who provide services essential to public safety. PacifiCorp is working on an updated version of the Public Safety Partner Portal which will be released in 2025.

2.2.4 PSPS Customer Notifications

Multiple communication channels are used for customer notifications, including:

- Outbound calls
- Social media updates
- Texts and emails
- Website update
- Press release
- Personal phone calls to AFN customers

Table 4 shows the PSPS notification plan for customers with AFN.[12]

Table 4. PacifiCorp's PSPS AFN Notification Plan

AFN Population Type	PSPS Notification Plan
Medical certificate	Standard PSPS notification via all available channels; plus additional PSPS notifications via personal phone calls; and in person welfare check if unable to reach via phone
Medical certificate with life support	Standard PSPS notification via all available channels; plus additional PSPS notifications via personal phone calls; and in person welfare check if unable to reach via phone
Medical baseline	Standard PSPS notification via all available channels; plus additional PSPS notifications via personal phone calls; and in person welfare check if unable to reach via phone
Access and functional needs, self-identified	Standard PSPS notification via all available channels; plus additional PSPS notifications via personal phone calls; and in person welfare check if unable to reach via phone
Limited English proficiency	Standard PSPS notification via all available channels
Tribes	Standard PSPS notification via all available channels; and media releases, social media, website; and Pacific Power's tribal liaison, emergency management personnel, public safety partners, ESF12, and/or regional business managers
People in remote areas	Standard PSPS notification via all available channels; and media releases, social media, website
Priority essential service organizations, including CBOs and critical facilities that serve AFN populations	Notifications via emergency management personnel, public safety partners, ESF12, and/or regional business managers; and via the public safety partner portal

[12] As found in the updated Table 13 – AFN Population Subset Notification Plan, location in R.18.12.005 PacifiCorp's 2024 PSPS Pre-Season Report available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/outages-safety/wildfire-safety/california-reports/R.18-12-005_PacifiCorp_2024_PSPS_Pre-Season_Report_PUBLIC_12-20-24.pdf

2.2.5 Community Resource Centers

Community resource centers (CRCs) are an integral part of ensuring community members affected by PSPS events have access to basic resources and up-to-date information. During a PSPS event, PacifiCorp closely coordinates with local public safety partners to determine CRC needs and locations. CRC locations are vetted using a checklist that was developed following guidance identified from the California Public Utilities Commission decisions and the current Americans with Disabilities Act Checklist for Emergency Shelters to ensure CRC services are equitable and accessible for medical baseline and access and functional needs populations.

PacifiCorp emergency management meets regularly with local and regional organizations that provide services to the AFN community, local emergency managers, and other support groups to ensure AFN and medical baseline needs are identified at CRCs, and that CRC resources are equitably distributed and accessible. When activated, the CRCs will be listed on the company's public website.

Services/resources provided at CRCs include:

✓ Shelter from environment ✓ Air conditioning ✓ Air Purifiers & Air Quality Monitors ✓ Potable water & non-perishable snacks ✓ Seating and tables ✓ Restroom facilities ✓ Refrigeration & heating for medicine and/or baby needs ✓ Interior and area lighting ✓ On-site security ✓ Televisions	✓ Ice and water ✓ Communications capability such as Wi-fi access, satellite phone, radio, cellular phone etc. ✓ On-site medical support (EMT-A at a minimum, paramedic preferred) ✓ Charging stations for cell phones, AM/FM/weather radios, computers, etc. ✓ Small crates for pets ✓ AFN/LEP population support ✓ Personal Protective Equipment ✓ Portable ADA ramp

PacifiCorp will continue to gather feedback from customers who utilize CRCs, logistics staff, the public utility commission and PacifiCorp employees in order to optimize CRC messaging, accessibility, support for medical and essential devices and the unmet needs of all customers including those who identify as AFN. Feedback is also gathered via printed surveys that are onsite at the CRC, online, and through customer service. Areas for improvement gathered via these feedback channels and through after-action reports will inform the next CRC Playbook update, scheduled for April 2025.

2.3 Recovery (After – Power has been restored)

2.3.1 AFN Support

AFN customers are contacted by customer service after the power is restored, as a continuation of the ongoing contact prior and throughout a PSPS event. The check-in ensures no additional support is needed for the customer after the power is restored.

Unmet AFN needs identified during post-re-energization wellness checks are escalated to the ECC. The AFN Coordinator or ECC Liaison would then coordinate with the local EOC to identify local resources to support the customer.

2.3.2 After Action Reviews and Reports

As with any other incident or event, after action reports are completed for PSPS responses. These reports provide an opportunity to identify what went well during the event execution and where improvements are needed. These findings are incorporated into future procedural improvements and as available, provided in the California Public Utility Commission post-event report in compliance with Resolution ESRB-8.

2.3.3 Lessons Learned and Feedback

PacifiCorp uses all events and incidents to gain feedback and identify future opportunities for improvement. As a part of the Company's internal improvement cycle the feedback and identified improvement opportunities are key measurements PacifiCorp uses to make corrections and adjust plans. Bi-annual customer surveys, CBO and partner interviews and ongoing reporting provide routine feedback and measurement of PacifiCorp's performance before, during, and after an event.

3. INFORMATION COLLECTION, ANALYSIS AND DISSEMINATION

PacifiCorp has contracts with three CBOs in California to share customer information. The information transfer is protected and is used to assist with CARE program Post Enrollment Verification (PEV), weatherization program, and receipt of energy assistance benefits. Additionally, the Company has an agreement with the State of California Department of Community Services and Development (CSD) for the Low-Income Home Energy Assistance Program. The agreement entitles agencies to customer information in PacifiCorp's Energy Assistance Portal to allow them to carry out provisions of LIHEAP (Low Income Home Energy Assistance Program). No other agreements for customer information sharing exist with local agencies, government agencies, or health providers.

4. AUTHORITIES AND REFERENCES

4.1 Annual Report and Emergency Response Plan in Compliance with General Order 166

PacifiCorp's Emergency Response Plan is updated annually and was last published in April 2024. All updates are in compliance with GO 166.

4.2 Phase 3 OIR PSPS Guidelines: AFN Plan and Quarterly Updates

Each IOU's annual AFN Plan and quarterly updates must incorporate, at a minimum, the six steps outlined in the Federal Emergency Management Administration's Comprehensive Preparedness Guide.

As PacifiCorp implements the 2025 AFN Plan, quarterly updates will be provided to the California Public Utility Commission. Revisions will be tracked each time the plan is modified and include descriptions, locations and date of the revisions made, and names of the persons responsible for the revisions.

5. CHANGE RECORD

Section	Person Responsible for Revision	Change	Date
Various	Various PacifiCorp Personnel	Various updates to align with 2024 Joint IOU AFN Plan and updates regarding AFN customer counts, survey results, website enhancements.	January 31, 2024
All	Various PacifiCorp Personnel	Updated • Significant updates in Section 1 to align with the Joint IOU's 2025 AFN Plan template • Tables and map • Content, order and flow of all sections of the Concept of Operations • Survey and interview findings located in Appendix D Added • Areas of focus in 2025 within the Concept of Operations • Customer Assistance Programs • Table 3. 2025 PSPS AFN Outreach Tactics and Initiatives • Table 4. PacifiCorp's PSPS AFN Notification Plan • New positions and responsibilities • Required training for ECC personnel • PacifiCorp's Wildfire Advisory Board roster to Appendix A which includes other AFN advisory groups	January 31, 2025