PLUMAS-SIERRA
RURAL ELECTRIC COOPERATIVE
WILDFIRE MITIGATION PLAN

2024 Update

I.

II. Mission Statement

The mission of Plumas-Sierra Rural Electric Cooperative (PSREC or the Cooperative) is to provide utility services with an elevated level of reliability for fair and reasonable costs. PSREC is dedicated to operating safe and dependable electric and telecommunication services while striving to improve the quality of life for member-owners and local communities.

The Cooperative works aggressively and proactively to manage and mitigate wildfire risk while operating and maintaining its system. The outcome of this approach is diligent stewardship of customer-owner investment in the Cooperative as it continues to construct, maintain, and operate its electric distribution system in a manner that minimizes catastrophic wildfire risk posed by its electrical lines and equipment. The Cooperative has applied careful consideration in the development of broad strategies to mitigate utility-posed wildfire risks while remaining consistent with the intention of Senate Bill 901 (SB 901) and other regulatory requirements.

The Cooperative acknowledges the California Public Utility Commission (CPUC) Fire-Threat Map (FTM) and recognizes that most of the Cooperative's power lines fall within Tier-2 designation, with a small portion in Tier 3. This wildfire mitigation plan (WMP or Plan) applies to all the Cooperative's service territory and has the goal of describing how the Cooperative constructs, maintains, and operates its electrical lines and equipment to minimize wildfire risk posed by its electrical equipment. This WMP describes specific strategies the Cooperative uses to reduce wildfire risk in Cooperative service territory areas designated as High or Extreme Fire-Threat Areas (Tier 2 and Tier 3), This methodology will be evaluated annually, and adjustments will be made as new or substantive information becomes available.

The Cooperative will continually coordinate with local fire and safety officials in the development and subsequent annual review of this Plan.

III. Utility Overview and Context

Plumas-Sierra Rural Electric Cooperative was founded in 1937 and energized on September 4, 1938, bringing power to Plumas, Lassen, and Sierra counties. PSREC is committed to improving the quality of life of member-owners and local communities. PSREC is consumer-owned and not-for-profit; any revenue beyond expenses is eventually returned to members in the form of capital credit payments. PSREC is committed to providing the best possible service at the lowest possible cost. PSREC takes pride in its cooperative—a grassroots system of service started by pioneers like those who settled this area. Keeping the cost of electricity affordable helps keep local businesses competitive while preserving the local rural heritage and standard of living. PSREC serves four counties (including Washoe County, Nevada) ranging from high desert to the 6,000 feet in elevation in the High Sierras.

A. Utility Description and Context Setting Table

Table 1: PSREC Context Summary

PSREC		
Service Territory Size	1, 648 square miles	
Owned Assets	☒ Transmission 159 miles ☒ Distribution 1,312 miles ☒ Generation 6Mw Natural Gas Co-gen	
Number of Customers Served	Customers: 9,698 services in place, 6,680 members	
Population Within Service Territory	16,000 (estimate)	
Customer Class Makeup	**Number of Accounts**	**Share of Total Load (MWh)**
	89% Residential 9% Business/Government 2% Irrigators	44% Residential 47% Business/Government 9% Irrigators
Service Territory Location/Topography	☒ Urban ☒ Wildland ☒ Rural/Forest ☒ Rural/Desert ☒Urban Interface ☒ Rural/Agriculture	
Service Territory Wildland Urban Interface (based on total area)	10 % WUI, Interface; 20 % WUI, Intermix; 70 % Non-WUI, Vegetated	
Percent of Service Territory in CPUC High Fire-Threat Districts (based on total area)	• Includes maps 63 % in Tier 2 0.38 % in Tier 3	
Prevailing Wind Directions & Speeds by Season	☐ Includes maps ☒ Includes a description-PSREC service territory covers a variety of terrain types and elevations. The prevailing wind data listed below are from four Remote Automated Weather Stations (RAWS) within the PSREC Service Territory and represent the variety of conditions that are present. Location — Prevailing Wind Direction (Annual Mean Wind Direction Deg.) Pierce RAWS 301 Cashman RAWS 208 Quincy Rd RAWS 259 Ravendale RAWS 235 Doyle RAWS 149	
Miles of Owned Lines Underground and/or Overhead	159 miles of 69KV Transmission 889 miles of overhead distribution	

PSREC		
	263 miles of underground distribution	
	Total miles = 1,312 Miles	
Percent of Owned Lines in CPUC High Fire-Threat Districts	Overhead Distribution Lines as % of Total Distribution System (Inside and Outside Service Territory)	0.09 %
	Overhead Transmission Lines as % of Total Transmission System (Inside and Outside Service Territory)	0.25 %
Customers have ever lost service due to an IOU PSPS event?		Yes
Customers have ever been notified of a potential loss of service due to a forecasted IOU PSPS event?		Yes
Has developed protocols to pre-emptively shut off electricity in response to elevated wildfire risks?		Yes
Has previously pre-emptively shut off electricity in response to elevated wildfire risk?		No

B. Statutory Cross-Reference Table

Table 2: Compliance with Public Utilities Code Section 8387(b)

Requirement	Statutory Language	Plan Section
Persons Responsible	**PUC § 8387(b)(2)(A):** An accounting of the responsibilities of persons responsible for executing the plan.	Sec. V.A.
Objectives of the Plan	**PUC § 8387(b)(2)(B):** The objectives of the wildfire mitigation plan.	Sec. IV. A.B.C.
Preventative Strategies	**PUC § 8387(b)(2)(C):** A description of the preventive strategies and programs to be adopted by the local publicly owned electric utility or electrical cooperative to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks.	Sec. VII. A.-K.
Evaluation Metrics	**PUC § 8387(b)(2)(D):** A description of the metrics the local publicly owned electric utility or electrical cooperative plans to use to evaluate the wildfire mitigation plan's performance and the assumptions that underlie the use of those metrics.	Sec. X.A.
Impact of Metrics	**PUC § 8387(b)(2)(E):** A discussion of how the application of previously identified metrics to previous wildfire mitigation plan performances has informed the wildfire mitigation plan.	Sec. X.B.

Requirement	Statutory Language	Plan Section
Deenergization Protocols	**PUC § 8387(b)(2)(F):** Protocols for disabling reclosers and deenergizing portions of the electrical distribution system that consider the associated impacts on public safety, as well as protocols related to mitigating the public safety impacts of those protocols, including impacts on critical first responders and on health and communication infrastructure.	Sec. VII.H.
Customer Notification Procedures	**PUC § 8387(b)(2)(G):** Appropriate and feasible procedures for notifying a customer who may be impacted by the deenergizing of electrical lines. The procedures shall consider the need to notify, as a priority, critical first responders, health care facilities, and operators of telecommunications infrastructure.	Sec. V.B. C.
Vegetation Management	**PUC § 8387(b)(2)(H):** Plans for vegetation management.	Sec. VII.D.
Inspections	**PUC § 8387(b)(2)(I):** Plans for inspections of the local publicly owned electric utility's or electrical cooperative's electrical infrastructure.	Sec. VII.E.
Prioritization of Wildfire Risks	**PUC § 8387(b)(2)(J): A** list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the local publicly owned electric utility's or electrical cooperative's service territory. The list shall include, but not be limited to, both of the following: i. Risks and risk drivers associated with design, construction, operation, and maintenance of the local publicly owned electric utility's or electrical cooperative's equipment and facilities. ii. Particular risks and risk drivers associated with topographic and climatological risk factors throughout the different parts of the local publicly owned electric utility's or electrical cooperative's service territory.	Sec. VI.A.

Requirement	Statutory Language	Plan Section
CPUC Fire-Threat Map Adjustments	**PUC § 8387(b)(2)(K):** Identification of any geographic area in the local publicly owned electric utility's or electrical cooperative's service territory that is a higher wildfire threat than is identified in a commission fire threat map, and identification of where the commission should expand a high fire threat district based on new information or changes to the environment.	Sec. VI.C.
Enterprise-Wide Risks	**PUC § 8387(b)(2)(L):** A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk.	Sec. VI.B.
Restoration of Service	**PUC § 8387(b)(2)(M):** A statement of how the local publicly owned electric utility or electrical cooperative will restore service after a wildfire.	Sec. IX.
Monitor and Audit	**PUC § 8387(b)(2)(N):** A description of the processes and procedures the local publicly owned electric utility or electrical cooperative shall use to do all of the following i. Monitor and audit the implementation of the wildfire mitigation plan. ii. Identify any deficiencies in the wildfire mitigation plan or its implementation and correct those deficiencies. iii. Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors that are carried out under the plan, other applicable statutes, or commission rules.	Sec. X.C.

Requirement	Statutory Language	Plan Section
Qualified Independent Evaluator	**PUC § 8387(c):** The local publicly owned electric utility or electrical cooperative shall contract with a qualified independent evaluator with experience in assessing the safe operation of electrical infrastructure to review and assess the comprehensiveness of its wildfire mitigation plan. The independent evaluator shall issue a report that shall be made available on the Internet Web site of the local publicly owned electric utility or electrical cooperative and shall present the report at a public meeting of the local publicly owned electric utility's or electrical cooperative's governing board.	Sec. XI.

C. Process for Utility Adoption and Submittal of Annual WMP and Opportunities for Public Comment

PSREC presents the wildfire mitigation plan to the Board of Public Utilities (the Board) on an annual basis. As part of the Board agenda publishing process, the public has 12 days to review all materials as well as comment at the public meeting. The Plan is subject to direct approval by the Cooperative's Board of Directors, and the General Manager implements it. The plan is submitted to the Office of Energy Infrastructure Safety. A qualified independent evaluator report will be presented to the Board when comprehensive updates are made, at least once every three years.

D. Description of Where WMP Information Can Be Found on Utility Website The 2024 plan, prior year's plans, and reference materials can be found on PSREC's website at https://www.psrec.coop/.

E. Purpose of the Wildfire Mitigation Plan

This wildfire mitigation plan (WMP or Plan) describes measures the Cooperative takes to mitigate the threat of Cooperative equipment-ignited wildfires. Included within the Plan is an explanation of various programs, practices, and procedures the Cooperative utilizes to comply with SB 901.

This Plan is subject to direct approval by the Cooperative's Board of Directors, and the General Manager implements the Plan. This Plan complies with the requirements of Public Utilities Code Section 8387 for publicly owned electric utilities to prepare a wildfire mitigation plan by January 1, 2020, and annually review it thereafter.

IV. Organization of the Wildfire Mitigation Plan

This wildfire mitigation plan includes the following elements:

- Utility overview and context
- Plan objectives
- Roles and responsibilities for carrying out the plan
- Identification of key wildfire risks and risk drivers
- Description of wildfire mitigation strategies
- Metrics for measuring the performance of the plan and identifying areas for improvement
- Description of community outreach and education, covering as appropriate communication about wildfire prevention, utility wildfire mitigation efforts and strategies, and potential deenergization and reenergization practices.

V. Objectives of the Wildfire Mitigation Plan

A. Minimizing Sources of Ignition

The primary goal of this Plan is to minimize the possibility that the Cooperative's facilities may be an original or contributing, however unlikely, source of wildfire ignition. The Cooperative has evaluated system improvements, operational procedures, and training to help meet this objective. Further, the Cooperative is updating best management practices to reflect its commitment to sensible system management and will explore new opportunities each year for improving the efficacy of the Plan.

The Cooperative utilizes the California Public Utility Commission (CPUC) State-Wide Fire Threat Map (Map) adopted January 19, 2018, in addition to informational fire-threat maps from other State of California government agencies to inform and aid in the development of this Plan and its subsequent updating. The CPUC Map designates a majority of the Cooperative's service territory as Tier-2 while identifying a minor portion of the system (LaPorte Road) as Tier 3 (extreme). A percentage of the service territory (Sierra Valley and the Highway 395 Corridor from Doyle to Susanville) is identified as Tier 1 or exempt from the High Fire-Threat District (HFTD).

B. Resiliency of the Electric Grid

Along with creating a WMP, the Cooperative realizes the opportunity to improve resiliency by hardening the system. The National Infrastructure Advisory Council[1] defines system resiliency as the ability to reduce the magnitude and/or duration of disruptive events. As part of this Plan's development, the Cooperative assesses new industry practices and technologies that may reduce the likelihood of service disruption or improve the service-restoration timeline.

To accomplish this, the Cooperative utilizes heavy-loading construction design standards per the Rural Utilities Service (RUS)[2] guidelines. The Cooperative's facilities are designed to withstand sustained heavy wind and snow and ice loading. The Cooperative also utilizes FR3 insulating fluid, current limiting fuses, and electronic reclosers along with real-time monitoring via Supervisory Control and Data Acquisition (SCADA) to all substations. Aggressive vegetation management continues to be a high priority, among other operational practices.

C. Minimizing Unnecessary or Ineffective Actions

The final goal of this Plan is to measure the effectiveness of specific mitigation strategies as they apply to the Cooperative. Where a particular action, program, or protocol is determined to be unnecessary or ineffective, the Cooperative will evaluate whether modification or replacement is suitable. This approach will also help determine if more cost-effective measures would produce the same or better results.

VI. Roles and Responsibilities

A. PSREC WMP Roles and Responsibilities

The Cooperative utilizes a Board/General Manager reporting hierarchy. Cooperative member-owners elect board members to rotating three-year terms, representing constituents across the Cooperative's seven-district service territory. The Board President and Vice President are in title; the Board nominates and appoints these positions annually. The Board is responsible for the adoption of all policies and delegates the operational implementation of policy to the General Manager:

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[1] The President's National Infrastructure Advisory Council (NAIC) includes executive leaders from private sector and state/local government who advise the White House on how to reduce physical and cyber risks and improve the security and resilience of the nation's critical infrastructure sectors.
[2] The Rural Utilities Service provides funding for the development of rural utilities infrastructure such as water, waste management, power, and telecommunications.

The General Manager has full operational authority of the Cooperative and operates as the Chief Executive, reporting directly to the Board. The General Manager provides direction and management to all Cooperative staff while implementing Board-adopted policy. The Manager of Engineering and Operations and the Member and Energy Services Manager serve as the Cooperative's public liaisons to outside agencies as well as responding to information

The Manager of Engineering and Operations oversees the daily electric utility operations, including construction, maintenance, energy control, fleet, vegetation management, and other ancillary daily duties. The Electric Operations Manager maintains functional management of assigned divisions within the Electric Utility and reports to the General Manager.

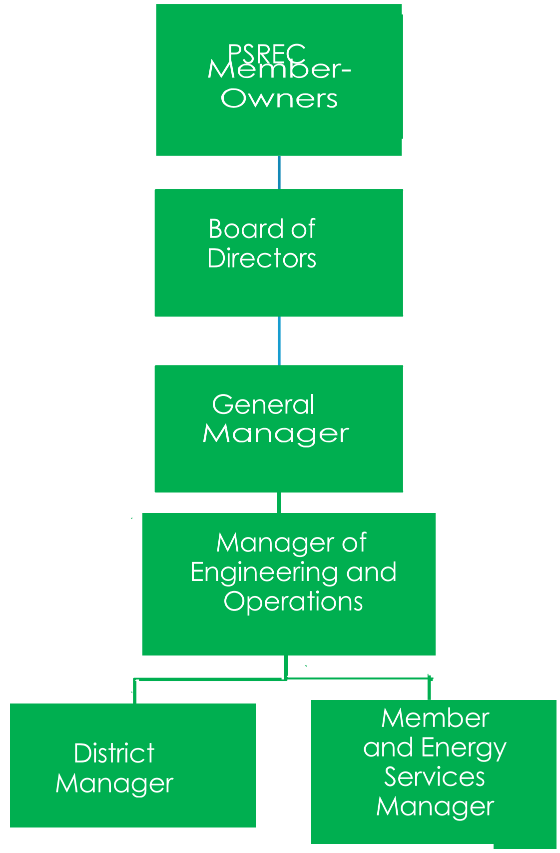

Figure 1. PSREC Hierarchy.

The Member and Energy Services Manager is responsible for providing all communications regarding current, potential, and planned outages to PSREC members via various communication channels, including text message, email, social media, local media outlets, and PSREC's website. Additionally, the Member and Energy Services Manager communicates to members planned and potential PSPS and emergencies.

Cooperative staff have the following responsibilities regarding fire prevention, response, and investigation:

- Conduct work in a manner that will minimize potential fire dangers.
- Take all reasonable and practicable actions to prevent and suppress fires resulting from PSREC electric facilities.
- Coordinate with federal, state, and local fire management personnel to ensure that appropriate preventative measures are in place.
- Immediately report fires, pursuant to specified procedures.
- Take corrective action when observing or having been notified that fire protection measures have not been properly installed or maintained.

- Ensure compliance with relevant federal, state, and industry standard requirements.
- Ensure that wildfire data is appropriately collected.
- Maintain adequate training programs for all relevant employees.

B. Coordination with Water Utilities/Department

PSREC has identified priority essential services that include Community Service Districts, which are facilities associated with the provision of drinking water or processing of wastewater, including facilities used to pump; divert; transport; store; treat; and deliver water and wastewater and provide for firefighting water supplies. When notified of a possible PSPS event, PSREC will communicate with local water agencies in advance so the facility can pump or fill any water storage tanks for fire operations and drinking water. During an actual PSPS, PSREC will continue outreach and monitor water facilities conditions or concerns.

C. Coordination with Communication Infrastructure Providers

Plumas-Sierra Telecommunications (PST) is a subsidiary of the Cooperative, providing broadband Internet service to approximately 2,800 customers. When PSREC operations could or are known to impact Internet service, PSREC and PST staff will coordinate so as to mitigate, or where practicable, eliminate the impact on electric and/or broadband service continuity. PSREC staff will collaborate proactively with PST staff to coordinate planned outages and communicate as quickly as possible during emergency power outages that impact one or both operations. This emergency notification will be extended to emergency services organizations and businesses.

Communications providers in the Cooperative’s service territory are notified of planned outages via phone, email, and available text alert service. Additionally, during emergency operations, Cooperative staff update the customer-facing information website dashboard at https://www.psrec.coop/ and all Cooperative social media outlets.

D. Standardized Emergency Management System

In an emergency, PSREC is classified as a local governmental agency.[3] PSREC has planning, communication, and coordination obligations pursuant to the California Office of Emergency Services' Standardized Emergency Management System (SEMS) Regulations,[4] adopted in accordance with Government Code section 8607. The SEMS Regulations specify roles, responsibilities, and structures of communications at five distinct levels: field response, local government, operational area, regional, and state.[5] Pursuant to this structure, PSREC regularly coordinates and communicates with the relevant safety agencies as well as other relevant local and state agencies.

The Cooperative will support Emergency Operation Center (EOC) operations when requested by an emergency manager representing local or state agencies. Support could include the exchange of information, supplying resources, or staffing an EOC.

Under the SEMS structure, a significant amount of preparation is done through advanced planning at the county level, including the coordination effort of public, private, and nonprofit organizations. The Cooperative's service territory resides in Lassen, Plumas, Sierra, and Washoe (Nevada) counties. The Operational Area includes local and regional organizations that bring relevant expertise to the wildfire prevention and recovery planning process. These participants include the following:

- Director of Emergency Services
- City of Portola (or designee)
- City of Loyalton (or designee)
- City of Susanville (or designee)

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[3] As defined in Cal. Gov. Code § 8680.2.
[4] 19 CCR § 2407.
[5] 19 CCR § 2403(b).

(1) "Field response level" commands emergency response personnel and resources to carry out tactical decisions and activities in direct response to an incident or threat.

(2) "Local government level" manages and coordinates the overall emergency response and recovery activities within their jurisdiction.

(3) "Operational area level" manages and/or coordinates information, resources, and priorities among local governments within the operational area and serves as the coordination and communication link between the local government level and the regional level.

(4) "Regional level" manages and coordinates information and resources among operational areas within the mutual aid region designated pursuant to Government Code §8600 and between the operational areas and the state level. This level, along with the state level, coordinates overall state agency support for emergency response activities.

(5) "State level" manages state resources in response to the emergency needs of the other levels, manages and coordinates mutual aid among the mutual aid regions and between the regional level and state level, and serves as the coordination and communication link with the federal disaster response system.

- Local Law Enforcement
- Local Volunteer Fire Departments
- Plumas National Forest (or designee)
- Lassen National Forest (or designee)
- Tahoe National Forest (designee)
- California Department of Forestry & Fire Protection (or designee)
- Pacific Gas & Electric (or designee)
- Nevada Energy (or designee)
- Liberty Energy (or designee)
- Northern California Power Agency (NCPA)
- Such others as the Board requests be in attendance

Pursuant to the SEMS structure, the Cooperative participates in training exercises with its counterparts both in field drills and tabletop exercises.

The Cooperative is also a member of the California Utility Emergency Association, which plays a key role in ensuring communications between utilities and emergency responders during emergencies.

VII. Wildfire Risks and Drivers Associated with Design, Construction, Operation, and Maintenance

A. Particular Risks and Risk Drivers Associated with Topographic and Climatological Risk Factors

Within the Cooperative's service territory and the surrounding areas, the primary wildfire risks are the following:

- Extended drought
- Vegetation type
- Vegetation density
- Weather
- High winds
- Terrain
- Tree mortality
- Lack of early fall precipitation (changing weather patterns or climate change)
- Fire history

PSREC is divided into distinct "North" and "South" service territories, and each present unique challenges and wildfire potential. The North end is situated in high-elevation desert, comprised of mostly shrub-like vegetation such as sagebrush, bitterbrush, and juniper. This area also experiences high wind speeds throughout the year, which can be an attribute of fast-moving wildland fires. The South end is situated in dense, mixed conifer forest in steep, mountainous terrain, specifically within the Highway 70 corridor from Quincy to Beckwourth. This area on the South End of the system, which contains the only Tier 3 designation on the HFTD Map, is the area of greatest concern for PSREC, as it could potentially affect the transmission feed from Pacific Gas and Electric (PG&E) at the Quincy 1 substation.

B. Enterprise-Wide Safety Risks

The Cooperative will use a methodical approach to address/mitigate enterprise safety risks. This approach will utilize Risk Factor Analysis (RFA). RFA is a process to identify and manage potential risks that could undermine core business functions, threaten business continuity, or impact recovery. The Cooperative has recently deployed Protection Zone Management (PZM) to aid in identifying areas of elevated risk. RFA will be used to qualitatively analyze safety risks, which include the following:

- Unavailability, or limited power supply of PG&E's transmission (Interconnection at Quincy substation)
- Unavailability, or limited power supply of NV Energy/Sierra Pacific's alternate transmission feed (Marble substation)
- Loss of Internet connectivity
- Loss of radio communications
- Loss of cellular communications
- Impacts of system deenergization
- Impacted roadways, limiting movement of personnel and equipment
- Impacted roadways, limiting access to Cooperative facilities (Headquarters, various substations, or alternate generation sites)

C. Changes to the CPUC Fire-Threat Map

The Cooperative does not recommend any changes to the CPUC State-Wide Fire-Threat Map, adopted on August 23, 2022, at this time. Future changes in Cooperative knowledge or recommendations going forward will be communicated as required by statute. However, the Cooperative's main transmission source is PG&E's 60 kV line, which lies in a small portion of the Tier-3 designated area, which is located in an urban landscape. In the event of a PG&E PSPS in that area, the majority of the Cooperative's members could be adversely affected.

VIII. Wildfire Preventative Strategies

A. High Fire-Threat District

The Cooperative participated in the development of the California Public Utilities Commission's (CPUC) Fire-Threat Map,6 which designates the HFTD. In the map development process, the Cooperative served as a territory lead and collaborated with Cooperative staff and local fire officials to identify areas of the Cooperative's service territory that are at an elevated or extreme risk of power line-ignited wildfire. The Cooperative incorporated the High Fire-Threat District (HFTD) into its construction, inspection, operation, maintenance, repair, and vegetation management practices.

B. Weather Monitoring

The Cooperative monitors current and forecasted weather data from a variety of sources, including the following:

- The National Oceanic and Atmospheric Administration (NOAA)
- United States National Weather Service (NWS)
- United States Forest Service Wildland Fire Assessment System
- National Fire Danger Rating System
- National Interagency Fire Center – Predictive Services for Northern and Southern California
- Internal knowledge of local conditions

[6] [4] Adopted by CPUC Decision 17-12-024.

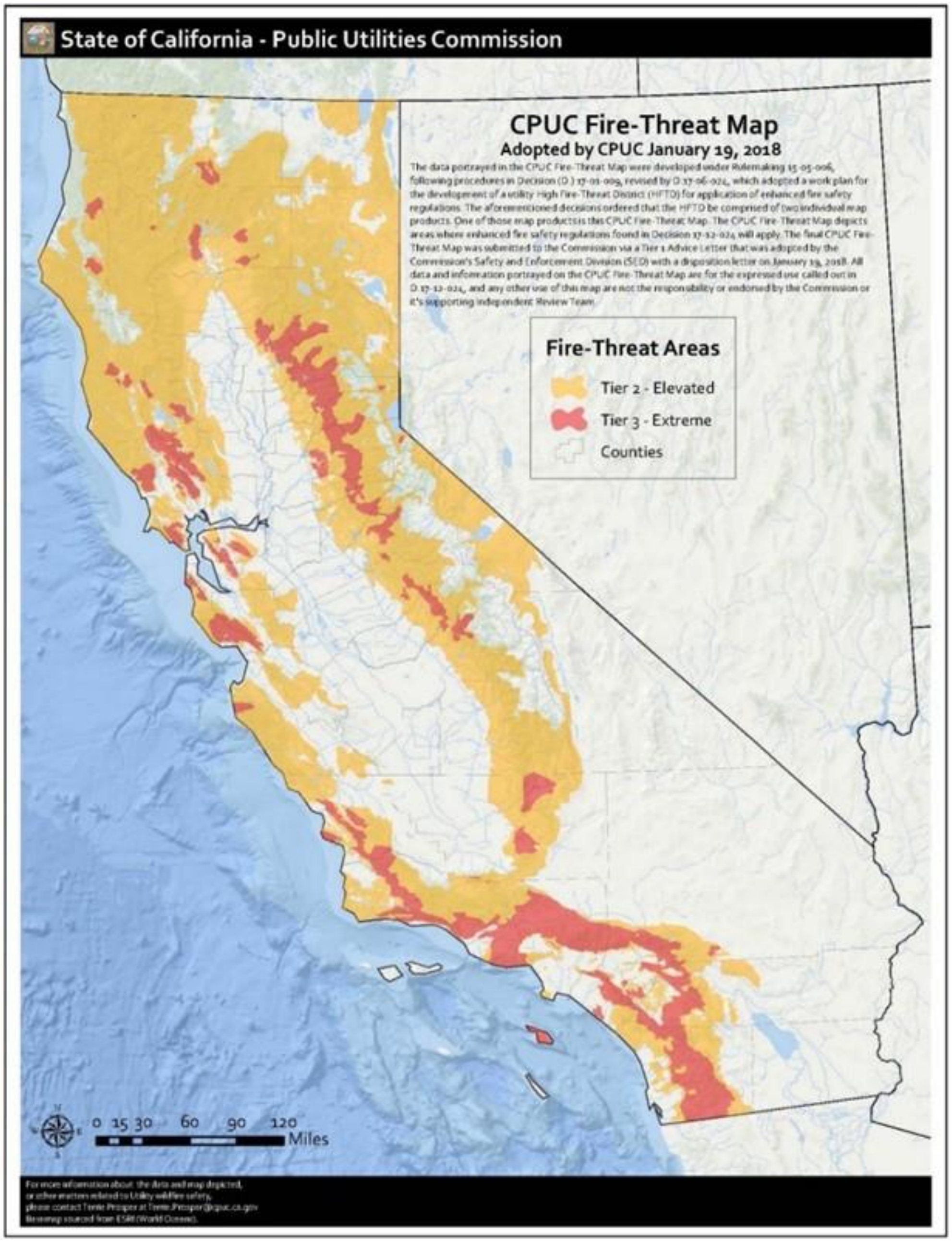


Figure 2. CPUC Fire-Threat Map.

The Cooperative will evaluate the cost and benefit of recent technologies where practicable. Each day, the Cooperative will assign one of four operating conditions based on the relevant weather data and knowledge of local conditions:

- **Normal:** During normal conditions, no changes are made to operations or work procedures.

- **Elevated:** During elevated fire-risk conditions, Cooperative staff will perform normal work with an elevated level of observation for environmental factors that could lead to an ignition.
- **Extreme:** During extreme fire-risk conditions, the Cooperative may delay routine work on energized primary lines (12.47kV and 69kV). The Cooperative may perform necessary work to preserve facilities or property. Extreme weather is defined as weather phenomena that are at the extremes of historical distributions and are rare for a particular place and/or time, especially severe or unseasonal weather. Such extremes include severe thunderstorms, severe snowstorms, ice storms, blizzards, flooding, high winds, or heat waves.
- **Red Flag:** If the National Weather Service declares a Red Flag Warning (RFW) for any portion of the Cooperative's service territory, the Cooperative will delay all routine work on energized primary lines (12.47kV & 69kV). The Cooperative may perform necessary work to preserve facilities or property.

C. Design and Construction Standards

Cooperative electric facilities are designed and constructed to meet or exceed relevant Federal, State, and industry standards. The Cooperative treats the State of California, General Order 95 (GO 95) as a guiding standard for the design and construction of overhead electrical facilities. The Cooperative meets or exceeds all standards in GO 95 and constructs its facilities consistent with a "heavy-loading" district as defined by the CPUC (Exhibit B). As a result of this approach, the Cooperative's system is hardened and more resilient to extreme weather events than systems that do not build to a heavy-loading district.

The Cooperative monitors trends in materials, technology, and work methods to evaluate prudent operational changes to enhance the efficacy of wildfire mitigation.

D. Vegetation Management

The Cooperative meets or exceeds the minimum industry standard(s) for vegetation management practices. For distribution-level facilities, the Cooperative meets (1) Public Resources Code section 4292; (2) Public Resources Code section 4293; (3) GO 95 Rule 35 (Exhibit C); and (4) the GO 95 Appendix E Guidelines to Rule 35 (Exhibit D). These standards require significantly increased clearances in an HFTD area. The time-of-trim guidelines do not establish a mandatory standard but instead provide guidance to utilities. The Cooperative will use specific knowledge of growing conditions and tree species to determine the appropriate time-of-trim clearance in each circumstance.

The Cooperative has developed a comprehensive Vegetation Management Plan (VMP) that complies with the aforementioned statutes. In addition, the VMP is subject to updates from time to time as practices and technology evolve.

The Cooperative employs an in-house timber feller, three contract vegetation management crews, and a registered forester on staff. The Cooperative performs tree trimming and clearing year-round, except during times of inclement weather. Additionally, The Cooperative has begun to reclaim right-of-way access roads in order to perform maintenance along with augmenting quicker response times for emergency responders.

(Vegetation management practices within the Cooperative's service territory are governed by: Public Resource Code 4292; Public Resource Code 4293; and, California General Order 95, Rule 35.).

E. Inspections

The Cooperative meets or exceeds the minimum inspection requirements provided in CPUC GO 165, Table 1 (Exhibit E) and CPUC GO 95, Rule 18 (Exhibit F). Pursuant to these rules, the Cooperative inspects electric facilities in the High Fire-Threat District more frequently than its counterparts in non-HFTD areas. Additionally, Cooperative staff uses its knowledge of the specific environmental and geographical conditions to determine when areas may require more frequent inspections. The Cooperative utilizes GO 95 and GO 165 as its guiding documents, as part of a robust asset management/maintenance program. The Cooperative has also recently deployed two recent programs to support system-wide inspections: an unmanned aircraft (drone) program to inspect facilities, especially in the remote and rugged service territory; and Protection Zone Management (PZM), which archives inspections of system protection equipment, helping to mitigate problems before they arise.

The Cooperative's goal is to ensure that all inspections performed within its service territory are complete before the beginning of the historic fire season. The Cooperative meets or exceeds the minimum inspection requirements provided in CPUC GO 165, Table 1 (Exhibit E) and CPUC GO 95, Rule 18 (Exhibit F). Pursuant to these rules, the Cooperative inspects electric facilities in the High Fire-Threat District more frequently than its counterparts, typically by June 1. The Cooperative monitors drought conditions and other relevant factors throughout the year to determine if inspections should be completed on an adjusted timeline.

If Cooperative staff discovers a facility in need of repair that is owned by an entity other than the Cooperative, the Cooperative will notify the facility owner in writing, as well as notify the agency having jurisdiction.

F. Workforce Training

The Cooperative has *developed* rules and complementary training programs for its workforce to reduce the likelihood of wildfire ignition. All field staff will be trained in WMP content; trained in fire extinguisher proper use and storage; will be able to identify the closest fire extinguisher: and will be required during pre-job briefings to discuss the potential(s) for ignition and real-time environmental conditions (current and forecasted weather that coincides with the duration of work for the day).

Any wildfire ignition will be reported to management for follow-up.

G. Recloser Policy

Extreme Weather Events (Non-RFW)

The Cooperative may disable automatic reclosing functions at Cooperative substations during extreme weather (non-RFW) events. An extreme weather event is defined as weather phenomena that are at the extremes of the historical distribution and are rare for a particular place and/or time, or especially severe or unseasonal weather. Such extremes include but are not limited to severe thunderstorms, high winds, heat waves, severe snowstorms, ice storms, blizzards, or flooding.

Other operational factors may be considered when evaluating the appropriateness of disabling reclosers.

RFW Events

During RFW events, the Cooperative will disable all automatic reclosing functions for all Automatic Circuit Reclosers (ACRs or reclosers) on its system. This ensures there will be no circuit reclosing during RFW conditions (i.e., one-shot operation).

H. Deenergization

The Cooperative, due to its location from 3,000 to 6,000 feet elevation, experiences severe winter weather, including blizzards and atmospheric rivers. It is not uncommon for these extreme weather events to include rain, snow, ice, and winds in excess of 100 miles per hour. For these reasons, the Cooperative's overhead electric system is built to a heavy-loading construction standard.

In evaluating the efficacy of a Public Safety Power Shutoff (PSPS), the Cooperative considered many factors, including heavy-loading construction standards, which are hardened to withstand high wind, snow loading, and ice formation. In evaluating the efficacy of a PSPS, the Cooperative considered many factors, including heavy-loading construction standards that are hardened to withstand high wind, snow loading, and ice formation; the offset between when the Cooperative's overhead electric distribution system experiences its most severe weather threats (i.e., severe winter storm(s); and the weather conditions during Red Flag Warnings (RFWs) (i.e., typically in late summer/fall with only moderate weather threats); and the potential negative impacts to fire response, water supply, public safety, and emergency communications should a fire occur while the Cooperative has deenergized a portion or all of its system.

During RFWs, however, which again occur in late summer/fall, the winds that accompany these events are typically a fraction of what the Cooperative's overhead electric distribution system experiences in the winter and what predominately pine forests can withstand. During RFWs, the most probable cause of wildfire ignition is lightning strikes, transportation, illegal fireworks, or recreation.

At this time, the Cooperative is not mandated to implement a PSPS program. However, the Cooperative believes it is prudent to monitor high-risk areas within its service territory that the CPUC has designated Tier-2. When extreme weather conditions are forecast, the Cooperative will dispatch personnel to the field to monitor high-risk areas, and conditions will also be monitored remotely via SCADA and office personnel. In the event of extreme weather conditions, The Cooperative has identified the parameters in Table 3 as a quantitative threshold for a potential PSPS.

Table 3. Updated Quantitative Thresholds

Region	ERC	Wind Gust (mph)*	FWI*
Quincy Substation to Beckwourth Substation	>92nd percentile	>40 mph	>50

Region	ERC	Wind Gust (mph)*	FWI*
Beckwourth Substation to Leavitt Substation	>92nd percentile	>45 mph	>60

*6-hour average

Based on these thresholds, some areas may not experience any PSPS events in a non-drought year, as was the case in 2019. It is worthwhile to note that the actual frequency and duration of these events may vary due to variability in weather conditions from one year to another, especially during drought years. In summary, the Cooperative is currently managing the PSPS process based on the above thresholds in Table 3 as they balance a reasonable risk profile of last-resort mitigation measures with customer service interruptions.

While the Cooperative is willing to take whatever steps are necessary to protect the community and the public, the risks and potential consequences of initiating a PSPS are significant and extremely complex. Foremost concerns include the potential loss of water supply to fight wildfires due to loss of production wells and pumping facilities, negative impacts on emergency response and public safety due to the historic disruptions in Internet and cell phone service during periods of extended power outages, and the loss of key community infrastructure and operational efficiency that occurs during power outages.

Based on the above considerations, the risks of implementing a PSPS program seem to far outweigh the chances that the Cooperative's electric overhead distribution system would cause a catastrophic wildfire. The Cooperative, on a case-by-case basis, has historically and will continue to consider deenergizing a portion of its system in response to a known public safety issue or in response to a request from an outside emergency management/response agency. Any deenergizing will be performed in coordination with local partner agencies. The Cooperative will also monitor the evolution of PSPS implementation by other California electric utilities to continue to refine its evaluation of this important topic.

I. Tree Attachments (Legacy Attachments)

The Cooperative has legacy attachments to trees that consist of service drop(s), secondary conductor(s), or security lighting. Although these installations were permitted pursuant to 14 CCR §1257, the Cooperative does not engage in this practice for new installations.

Cooperative staff is in the process of developing a recommendation and operational practices to address these legacy attachments. The inclusive recommendation will consider the following:

- Pursuant to 14 CCR §1257, the Cooperative will inspect these installations on a periodic basis.
- Limbing of a tree used as an attachment point(s) will be consistent with 14 CCR §1257.
- The Cooperative may audit tree attachments on a periodic basis.

J. Proposed Service Requirements

Since circa 1995, the Cooperative Code has required most new or reconstructed developments to take service from the Cooperative via an underground system; however, exceptions do exist in the current Cooperative Code. The Cooperative seeks to minimize the installation of overhead power lines where practicable and will, therefore, recommend an underground requirement for all electric services and consider the following:

- The Cooperative will not attach to trees for any reason.
- The Cooperative may consider a cost-sharing program for customers that desire to convert an existing overhead service to an underground service.
- Customer(s) receiving service via legacy tree attachment(s) can request the Cooperative to remove the tree attachment and place a utility pole at the Cooperative's expense.

K. Potential Climate Change Effects and Strategies

Climate change is expected to cause increased temperatures, drier conditions, and insect outbreaks in the decades to come, all of which will likely increase wildfire risk, especially in the western United States. Climate change has affected the Cooperative's service territory in many ways, including altering vegetation; changing the start, finish, and duration of fire season; and increasing the number of extreme weather events such as fire weather warnings. Droughts are longer and more severe. Large storm events are more common and intense. Summers are hotter and may include more thunderstorms. These climate change factors affect vegetation near the Cooperative's infrastructure, affecting associated wildfire risks:

- The composition of vegetation cover changes, with some areas moving towards lighter, flashier fuels.
- Vegetation dries out during droughts, increasing fire danger.

- Stressed vegetation is more susceptible to insect infestations, damaging trees, or accelerating mortality.
- Thunderstorms present lightning strike risks along with strong wind events.

Extended periods of intense rainfall also typically increase landslide risks. In turn, landslides could damage or topple structures, limit access, create safety hazards by damaging roads, or cause localized tree mortality by severing root systems. Note that heavy rainfall is not the only landslide trigger mechanism, but it is the one most strongly associated with climate change.

The above changes anticipated with climate change in the Cooperative's service territory will likely require an increase in the frequency of practices that the Cooperative uses during extreme weather events, such as disabling reclosers or delaying routine equipment service.

Climate change may also result in a redrawing of the High Fire-Threat District and an expansion of the area where the Cooperative must perform tree trimming and surface vegetation management to the CPUC GO 95 standards for high fire-risk areas.

Because wildfire risk is tied to higher temperatures, drought, and flooding, comprehensive resilience planning for multiple impacts is critical for communities. In anticipation of future impacts on the Cooperative's operations and an increased risk of wildfire, the Cooperative has begun installing wildfire detection cameras at its substation while increasing cooperation with local agencies for emergency contact and notifications.

IX. Community Outreach and Public Awareness

As the local electric and Internet utility, the Cooperative has robust community outreach and marketing programs to effectively communicate with its customers and community. The Cooperative is active in the community, attending dozens of community events each year.

During its annual meeting, the Cooperative staffs educational booths to explain its member programs, including power and internet. This face-to-face communication includes providing information on the Cooperative's Vegetation Management (VM) Program, offering free deenergizing of customers' overhead service connections to allow them to clear defensible space while working safely, and educating the community on the Cooperative's overall efforts to respond to catastrophic wildfires. Information can also be found on the Cooperative's website.

The Cooperative also has robust marketing and communication efforts leveraging its website (www.psrec.coop), social media (Facebook/Twitter), bill stuffers, print ads, and digital marketing. The Cooperative is a regular advertiser in Feather Publishing's newspapers, as well as the Sierra Booster, Ruralite Magazine, and local JDX radio.

Regarding fire-related community outreach, the Cooperative has been continually active in promoting the Vegetation Management Program; including the recent regulatory changes increasing the vegetation clearances. The Cooperative sends out an annual bill insert to all customers along with information on the website, social media, digital media, print advertising, and radio.

X. Restoration of Service

Although the Cooperative has not activated a PSPS operational practice, if an outside emergency management/emergency response agency requests a power shutdown, or if the Cooperative elects to deenergize segments of its system due to extreme weather, Cooperative staff will patrol the affected portions of the system with boots on the ground and also with the drone before the system can be reenergized. Suspect equipment or distribution lines that cannot be patrolled will remain deenergized. In addition, system performance abnormalities will be monitored via the Cooperative's SCADA system.

XI. Evaluating of the Plan

A. Metrics and Assumptions for Measuring Plan Performance

The Cooperative will track two metrics to measure this Plan's performance: (1) the number of fire ignitions; and (2) the number of wire-down events within the service territory.

Metric 1: Fire Ignitions

For purposes of this metric, a fire ignition is defined as follows:

- The Cooperative facility was associated with the fire
- The fire was self-propagating and of a material other than electrical
- The resulting fire traveled greater than one linear meter from the ignition point
- The Cooperative has knowledge that the fire occurred

In future wildfire mitigation plans, the Cooperative will provide the number of fires that occurred that were less than 10 acres in size. Any fires greater than 10 acres will be individually described.

Metric 2: Wires Down

The second metric is the number of wire-down events within the Cooperative's service territory. For purposes of this metric, a wire-down event includes any instance where the primary distribution conductor falls to the ground or onto a foreign object, defined as any object not specifically an asset of the Cooperative (i.e., phone, cable, trees, etc.).

The Cooperative will not normalize this metric by excluding unusual events, (i.e., severe storms, car versus pole incidents, or snow unloading). However, the Cooperative will supplement this metric with a qualitative description of any such unusual events.

B. Impact of Metrics on the Plan

The Cooperative anticipates relatively limited data will be gathered through these metrics, particularly in the initial years. Therefore, it will be difficult to draw meaningful conclusions based on this data. The Cooperative will evaluate modifying these metrics or adding additional metrics in future years as more data becomes available and situational awareness continues to improve.

C. Monitoring and Auditing the Plan

Plumas Sierra Rural Electric Cooperative staff reviews the Plan annually. The review process includes presenting the Plan to the Cooperative's Board of Directors for review as well as presenting the Plan at the Cooperative's annual meeting for comment. After the annual review process is completed, a copy of the approved WMP is posted on the Cooperative's website and available to the public.

D. Identifying and Correcting Deficiencies in the Plan

The Manager of Engineering and Operations or his or her designee will at least, on a semi-annual basis, update the General Manager regarding the Plan's implementation, identified deficiencies, or recommendations for updating.

Achieving a robust, all-encompassing WMP to mitigate wildfire risk is the primary objective of this document. The staff has the role of vetting current procedures and recommending changes or enhancements to build upon non-optimized strategies in the Plan. Either due to unforeseen circumstances, regulatory changes, emerging technologies, or other rationales, deficiencies within the Plan will be sought out and reported to the Board annually in the form of an updated Plan.

The Manager of Engineering and Operations or his or her designee will be responsible for spearheading discussions on correcting deficiencies when updating the Plan for its annual presentation to the Board. All stakeholders are empowered to suggest improvement opportunities, including but not limited to field crews, management, auditors, fire safety professionals, and members of the public.

E. Monitoring the Effectiveness of Inspections

The Cooperative currently utilizes General Orders 95 (GO95) and 165 (GO165), respectively, as its guide to inspect its system. Field staff routinely patrol the service territory and correct deficiencies as they are encountered. The Cooperative tracks deficiencies that are repaired upon discovery within its Geographical Information System (GIS) and consistent with the guidelines of GO 95 and 165, respectively. Further, deficiencies that cannot be repaired upon discovery are assigned a priority level. The repairs are defined as Level 1 (highest), Level 2 (moderate), or Level 3 (lowest) as defined by GO 95, Rule 18 (Exhibit F), with the discovery, remedy, and supporting documentation being tracked within the Cooperative's GIS.

Cooperative staff will report as part of its annual WMP presentation to the Board the number of deficiencies found, the number of deficiencies repaired within the defined priority timeline, and the number of outstanding deficiencies that were not repaired within the defined timeline.

XII. Independent Auditor

In selecting an independent auditor, the Cooperative will utilize a process consistent with the Cooperative Purchasing Code. Additional considerations will include relevant industry experience; similar work for other municipal utilities or special Cooperatives; recognized expertise in line construction and maintenance; responsiveness; and familiarity with applicable California statutes (i.e., GO 95, GO 165, PRC 4292 and 4293, etc.).

The Cooperative will submit its draft report to an independent auditor, and the auditor's findings will be presented to the Board at a regular Board meeting.

XIII. Appendix

Exhibit A – California Public Utilities Commission Fire Threat Map, Adopted January 19, 2018

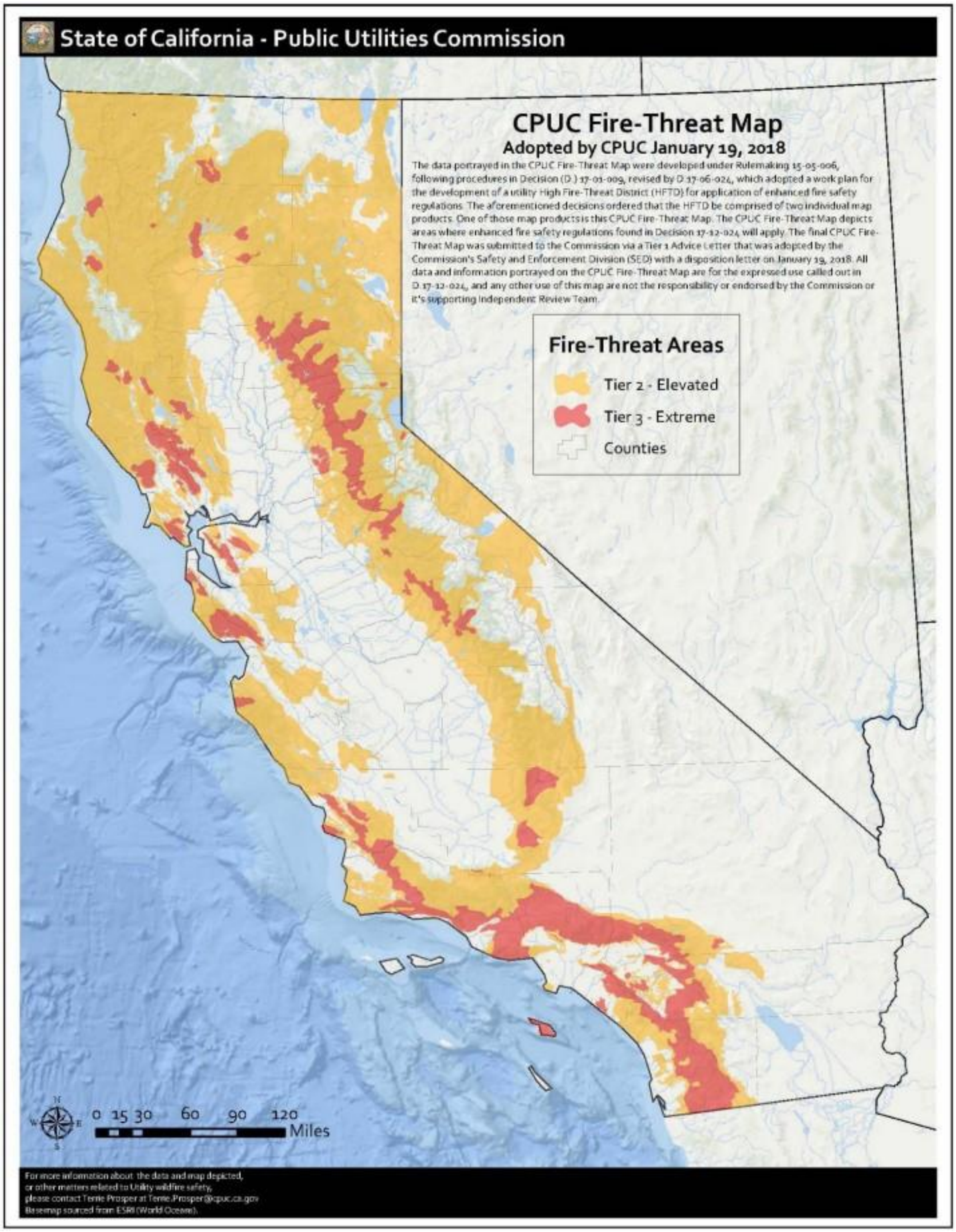
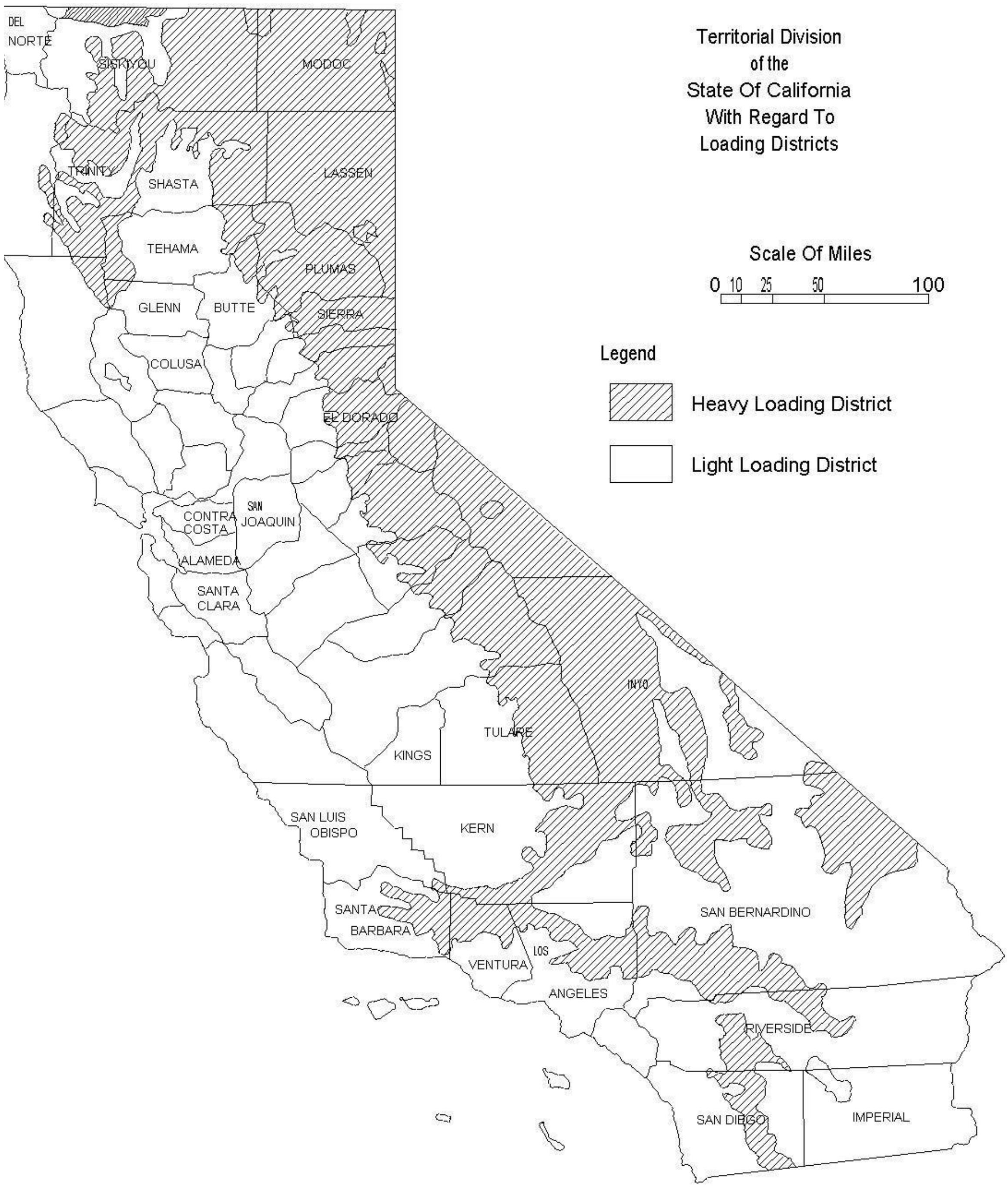


Exhibit B – California Public Utilities Commission, Heavy loading Cooperative Map



See Rules • 43.1 And • 43.2

Exhibit C – California Public Utilities Commission, General Order 95, Rule 35 Vegetation Management

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions, shall be

maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this General Order, including facilities on lands owned and maintained by California state and local agencies.

When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that dead, rotten or diseased trees or dead, rotten, or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of supply or communication lines, said trees or portions thereof should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that its circuit energized at 750 volts or less shows strain or evidence of abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension, rearranging, or replacing the conductor, pruning the vegetation, or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the vegetation and conductor. Scuffing or polishing of the insulation or covering is not considered abrasion. Strain on a conductor is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors, in and of itself, does not constitute a nonconformance with the rule.

Note: Revised January 13, 2006 by Decision No. 05-01-030, August 20, 2009 by Decision No. 09-08-029 and January 12, 2012 by Decision No. 12-01-032

Exceptions:

Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicable and the conductor is separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

Rule 35 requirements do not apply where the supply or communication company has made a "good faith" effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A "good faith" effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. The written communication may include a statement that the company may seek to recover any costs and liabilities incurred by the company due to its inability to trim or remove vegetation. However, this does not preclude other actions from demonstrating "good faith." If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the company is not compelled to comply with the requirements of exception 1.

The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the Commission may direct the utility to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase–in requirements.

Note: Revised November 6,1992 by Resolution No. SU–15, September 20, 1996 by Decision No. 96–09–097 and January 23, 1997 by Decision No. 97–01–044.

Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions. The utility shall bear the risk of determining whether this exemption applies, and the Commission shall have final authority to determine whether the exemption applies in any specific instance, and to order that corrective action be taken in accordance with this rule, if it determines that the exemption does not apply.

Note: Added October 22, 1997 by Decision No. 97–10–056

Exhibit D – California Public Utilities Commission, General Order 95 Appendix E

Clearance of Poles, Towers and Structures from Railroad Tracks

The following are guidelines to Rule 35 .

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area lands pursuant to Public Resource Code Sections 4102 and 4293.

Voltage of Lines	**Case 13 of Table 1**	**Case 14 of Table 1**
Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volts	4 feet	12 feet
Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts	6 feet	20 feet
Radial clearances for any conductor of a line operating at 110,000 or more volts but less than 300,000 volts	10 feet	30 feet
Radial clearance for any conductor of a line operating at 300,000 or more volts	15 feet	30 feet

Note: Added November 6, 1992 by Resolution SU–15 and revised September 20, 1996 by Decision No. 96–09–097 , August 20, 2009 by Decision No. 09-08-029, January 12, 2012 by Decision No. 12-01-032, December 21, 2017 by Decision 17-12-024.

Exhibit E – California Public Utilities Commission, General Order 165, Table 1, Distribution Inspection cycles

Distribution Inspection Cycles (Maximum Intervals in Years)

	Patrol		Detailed		Intrusive	
	Urban	Rural	Urban	Rural	Urban	Rural
Transformers						
Overhead	1	2[1]	5	5	---	---
Underground	1	2	3	3	---	---
Pad mounted	1	2	5	5	---	---
Switching/Protective Devices						
Overhead	1	2[1]	5	5	---	---
Underground	1	2	3	3	---	---
Pad mounted	1	2	5	5	---	---
Regulators/Capacitors						
Overhead	1	2[1]	5	5	---	---
Underground	1	2	3	3	---	---
Pad mounted	1	2	5	5	---	---
Overhead Conductor and Cables	1	2[1]	5	5	---	---
Street lighting	1	2	x	x	---	---
Wood Poles under 15 years	1	2	x	x	---	---
Wood Poles over 15 years which have not been subject to intrusive inspection	1	2	x	x	10	10
Wood poles which passed intrusive inspection	---	---	---	---	20	20

(1) Patrol inspections in rural areas shall be increased to once per year in Extreme and Very High-Fire-Threat Zones in the following counties: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura. Extreme and Very High-Fire-Threat Zones are designated on the Fire and Resource Assessment Program (FRAP) Map prepared by the California Department of Forestry and Fire Protection's Fire and Resource or the modified FRAP Map prepared by San Diego Gas & Electric Company (SDG&E) and adopted by Decision 12-01-032 in Phase 2 of Rulemaking 08-11-005.The fire threat map is to be used to establish approximate boundaries and Utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

Note: This General Order does not apply to cathodic protection systems associated with natural gas facilities.

Note: For the purpose of implementing the patrol and detailed inspection intervals in Table 1 above, the term "year" is defined as 12 consecutive calendar months starting the first full calendar month after an inspection is performed, plus or minus two full calendar months, not to exceed the end of the calendar year in which the next inspection is due.

Exhibit F – California Public Utilities Commission, General Order 95, Section I, Rule 18

General Provisions

18 Reporting and Resolution of Safety Hazards Discovered by Utilities

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

Resolution of Safety Hazards and General Order 95 Nonconformances

a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 nonconformances posed by its facilities.

Upon completion of the corrective action, the company's records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. These records shall be preserved by the company for at least ten (10) years and shall be made available to Commission staff upon 30 days' notice.

Where a communications company's or an electric utility's actions result in GO nonconformances for another entity, that entity's remedial action will be to transmit a single documented notice of identified nonconformances to the communications company or electric utility for compliance.

a) All companies shall establish an auditable maintenance program for their facilities and lines. All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or nonconformances with General Order 95 on the company's facilities.

The auditable maintenance program shall prioritize corrective actions consistent with the priority levels set forth below and based on the following factors, as appropriate:

Safety and reliability as specified in the priority levels below;

Type of facility or equipment;

Location, including whether the Safety Hazard or nonconformance is located in the High Fire-Threat District;

Accessibility;

Climate;

Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public.

There shall be 3 priority levels.

Level 1:

Immediate safety and/or reliability risk with high probability for significant impact.

Act immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

Level 2:

Variable (non-immediate high to low) safety and/or reliability risk.

Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).

Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed: (1) six months for nonconformances that create a fire risk located in Tier 3 of the High Fire-Threat District; (2) 12 months for nonconformances that create a fire risk located in Tier 2 of the High Fire-Threat District; (3) 12 months for nonconformances that compromise worker safety; and (4) 59 months for all other Level 2 nonconformances.

Level 3:

Acceptable safety and/or reliability risk.

Act (re-inspect, re-evaluate, or repair) as appropriate.

b) Correction times may be extended under reasonable circumstances, such as:

Third party refusal

Customer issue

No access

Permits required

System emergencies (e.g., fires, severe weather conditions)

Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

Notification of Safety Hazards

If a company, while performing inspections of its facilities, discovers a safety hazard(s) on or near a communications facility or electric facility involving another company, the inspecting company shall notify the other company and/or facility owner of such safety hazard(s) no later than 10 business days after the discovery. To the extent the inspecting company cannot determine the facility owner/operator, it shall contact the pole owner(s), who shall be responsible for promptly notifying the company owning/operating the facility with the safety hazard(s), normally not to exceed five business days after being notified of the safety hazard. The notification shall be documented and such documentation must be preserved by all parties for at least ten years.

Note: Each pole owner must be able to determine all other pole owners on poles it owns. Each pole owner must be able to determine all authorized entities that attach equipment on its portion of a pole.

Note: Added August 20, 2009 by Decision No. 09-08-029 and revised January 12, 2012 by Decision No. 12-01-032, December 21, 2017 by Decision No. 17-12-024.

Exhibit G – WSAB Utility Information Template

Utility Name	
Size in Square Miles	*1, 648 square miles*
Assets	☒ Transmission 159 miles ☒ Distribution 1312 miles ☒ Generation 6Mw Cogen
Number of Customers Served	*Customers:* 9,698 services in place 6,680 members
Customer Classes	☒ Residential ☒ Government ☒ Agricultural ☒ Small/Medium Business ☒ Commercial/Industrial
Location/Topography	☒ Urban ☒ Wildland Urban Interface ☒ Rural/Forest ☒ Rural/Desert ☒ Rural/Agriculture
Percent Territory in CPUC High Fire Threat Districts	☐ Includes maps 63 % in Tier 2 0.38 % in Tier 3
CAL FIRE FRAP Map Fire Threat Zones	Includes maps % Extreme % Very High % High
Existing Grid Hardening Measures	Describes hardened & non-hardened infrastructure: Aggressive vegetation management program including ROW mastication. Pole inspection program to identify aging poles, replacing with larger class poles. All PSREC substations are on SCADA, and we have SCADA-controlled field breakers and capacitor banks. PSREC substations can be loop fed from another substation. Alternate transmission feed
Utility Fire Threat Risk Level	☐ High ☐ Low ☒ Mixed

Impacted by another utility's PSPS?	☒ **Yes** ☐ **No**
Mitigates impact of another utility's PSPS?	☒ **Yes** ☐ **No**
Expects to initiate its own PSPS?	☐ **Yes** ☒ **No**
Prevailing wind directions & speeds by season	☐ **Includes maps** ☒ **Includes a description-PSREC service territory covers a variety of terrain types and elevations. The prevailing wind data listed below is from four Remote Automated Weather Stations (RAWS) within the PSREC Service Territory and represent the variety of conditions present.**

Location	Prevailing Wind Direction (Annual Mean Wind Direction Deg.)
Pierce RAWS	301
Cashman RAWS	208
Quincy Rd RAWS	259
Ravendale RAWS	235
Doyle RAWS	149

References

14CCR § 1257

March 26, 2019, Memorandum, RE: Disabling of Automatic Circuit Reclosers (ACRs) March 26, 2019, Memorandum, RE: Hotline Work during Extreme Weather or RFW Events

March 26, 2019, Memorandum, RE: Mandatory Reporting Requirements – Fire Ignition March 26, 2019, Memorandum, RE: Mandatory Reporting Requirements – Wire Down March 26, 2019, Memorandum, RE: Re-Energization of Lines

March 26, 2019, Memorandum, RE: Tree Attachments Public Resources Code section 4292

Public Resources Code Section 4293

Public Utilities Code Section 8387

State of California, General Order 95 State of California, General Order 165 Vegetation Management Plan (VMP)