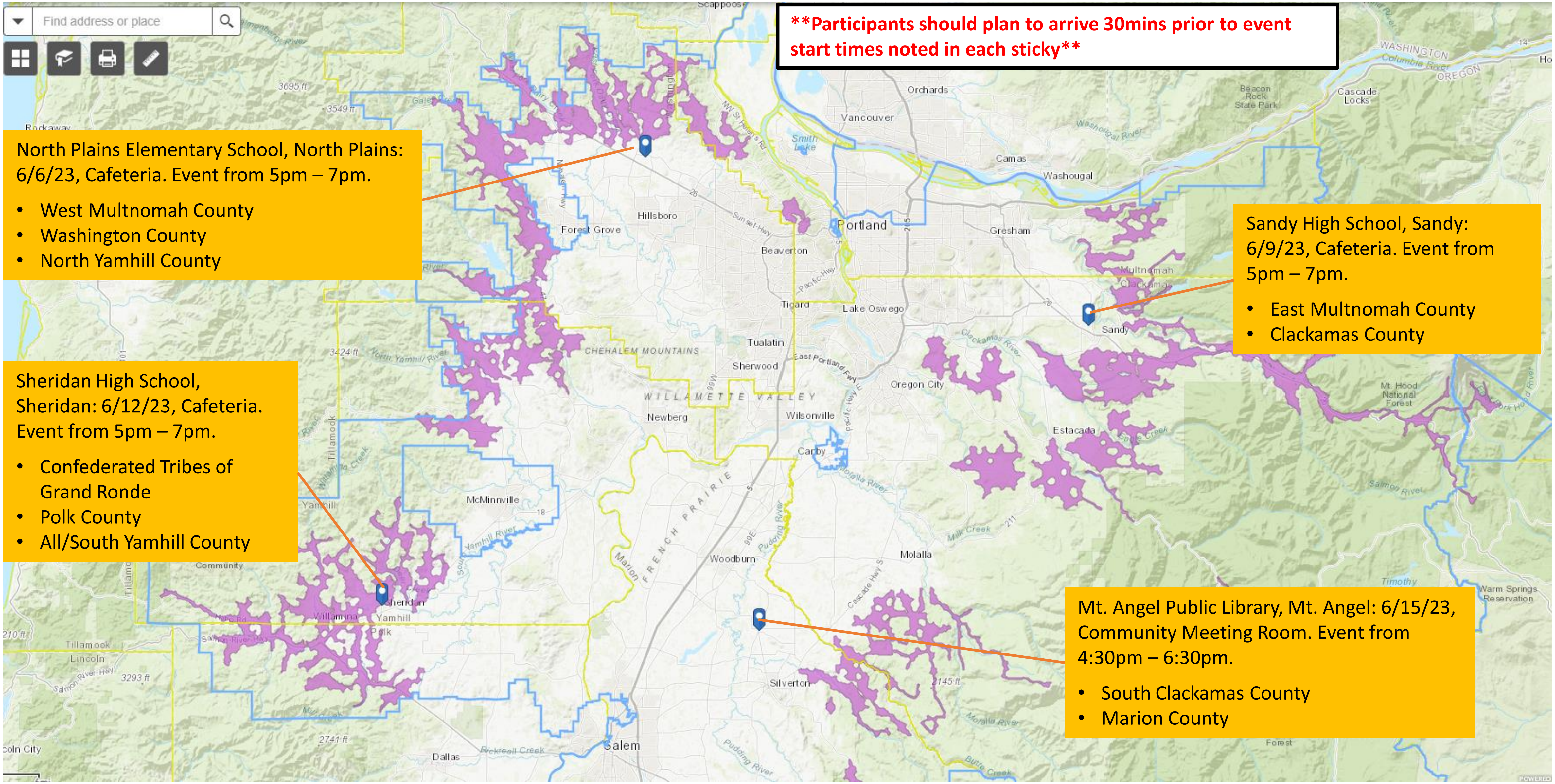
Participants should plan to arrive 30mins prior to event start times noted in each sticky



North Plains Elementary School, North Plains: 6/6/23, Cafeteria. Event from 5pm – 7pm.

- West Multnomah County
- Washington County
- North Yamhill County

Sandy High School, Sandy: 6/9/23, Cafeteria. Event from 5pm – 7pm.

- East Multnomah County
- Clackamas County

Sheridan High School, Sheridan: 6/12/23, Cafeteria. Event from 5pm – 7pm.

- Confederated Tribes of Grand Ronde
- Polk County
- All/South Yamhill County

Mt. Angel Public Library, Mt. Angel: 6/15/23, Community Meeting Room. Event from 4:30pm – 6:30pm.

- South Clackamas County
- Marion County

Public Utility Commission

Chapter 860

Division 300
WILDFIRE MITIGATION PLANS

860-300-0001
Scope and Applicability of Rules

(1) The rules in this division prescribe the filing requirements for risk-based Wildfire Mitigation Plans filed by a Public Utility that provides electric service in Oregon pursuant to ORS 757.005.

(2) Upon request or its own motion, the Commission may waive any of the rules in this division for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: ORS 756.040, ORS 757.035, ORS 757.039, ORS 757.649, ORS 759.030, ORS 759.040 & ORS 759.045
History:
PUC 6-2022, amend filed 09/22/2022, effective 09/22/2022
PUC 10-2021, adopt filed 12/01/2021, effective 12/01/2021

860-300-0010
Definitions for this Division

(1) "Communications" means media that communicate voice, data, text, or video over a distance using electrical, electronic, radio, microwave, or light wave transmissions.

(2) "ESF-12" refers to Emergency Support Function-12 and indicates the Commission's role in supporting the State Office of Emergency Management for energy utilities issues during an emergency.

(3) "Local Community" means any community of people living, or having rights or interests, in a distinct geographical area.

(4) "Local Emergency Management" means city, county, and tribal emergency management entities.

(5) "Near-term Wildfire Risk" means elements of wildfire risk that are expected to fluctuate on a daily or weekly basis. Examples include temperature, humidity, and wind.

(6) "Public Utility" has the meaning given to an "electric company" in ORS 757.600.

(7) "Public Safety Partners" means ESF-12, Local Emergency Management, and Oregon Department of Human Services (ODHS).

(8) "Public Safety Power Shutoff" or "PSPS" means a proactive de-energization of a portion of a Public Utility's electrical network, based on the forecasting of and measurement of extreme wildfire weather conditions.

(9) "Tabletop Exercise" means an activity in which key personnel, assigned emergency management roles and responsibilities, are gathered to discuss, in a non-threatening environment, various simulated emergency situations.

(10) "Utility-identified Critical Facilities" refers to the facilities the Public Utility identifies that, because of their function or importance, have the potential to threaten life safety or disrupt essential socioeconomic activities if their services are interrupted. Communications facilities and infrastructure are to be considered Critical Facilities.

(11) "Wildfire Mitigation Plan" is the same as a "wildfire protection plan" and refers to the document filed with the Commission relating to an electric utility's risk-based plan designed to protect public safety, reduce the risk of utility facilities causing wildfires, reduce risk to utility customers, and promote electric system resilience to wildfire damage.

Statutory/Other Authority: ORS 183, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: ORS 756.040, ORS 757.035, ORS 757.039, ORS 757.649, ORS 758.215, ORS 759.005 & ORS 759.045
History:
PUC 4-2022, adopt filed 05/24/2022, effective 05/24/2022

860-300-0020
Wildfire Protection Plan Filing Requirements

(1) Wildfire Mitigation Plans and Updates must, at a minimum, contain the following requirements as set forth in Section 3(2)(a)-(h), chapter 592, Oregon Laws 2021 and as supplemented below:

(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are:

(A) Within the service territory of the Public Utility, and

(B) Outside the service territory of the Public Utility but within the Public Utility's right-of-way for generation and transmission assets.

(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.

(c) Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.

(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjustingpower system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.

(e) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure, including a PSPS communication strategy consistent with OAR 860-300-0040 through 860-300-0050.

(f) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season, consistent with OAR 860-300-0040 and OAR 860-300-0050.

(g) Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0018.

(h) Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0018.

(i) Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.

(j) Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used to develop and implement cost effective wildfire mitigation solutions.

(k) Description of ignition inspection program, as described in Division 24 of these rules, including how the utility will determine, and instruct its inspectors to determine, conditions that could pose an ignition risk on its own equipment and on pole attachments.

(2) Wildfire Mitigation Plans must be updated annually and filed with the Commission no later than December 31 of each year. Public Utilities are required to provide a plan supplement explaining any material deviations from the applicable Wildfire Mitigation Plan acknowledged by the Commission. A Public Utility's initial Wildfire Protection Plan must be filed no later than December 31, 2021, per section 5, chapter 592, Oregon Laws 2021.

(3) Within 180 days of submission, Wildfire Mitigation Plans and Wildfire Plan Updates may be approved or approved with conditions through a process identified by the Commission in utility-specific proceedings, which may include retention of an Independent Evaluator (IE). For purposes of this section, "approved" means the Commission finds that the Wildfire Mitigation Plan or Update is based on reasonable and prudent practices including those the Public Utility identified through Commission workshops identified in SB 762, Section 2, and designed to meet all applicable rules and standards adopted by the Commission.

(4) Approval of a Wildfire Mitigation Plan or Update does not establish a defense to any enforcement action for violation of a Commission decision, order or rule or relieve a Public Utility from proactively managing wildfire risk, including by monitoring emerging practices and technologies.

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: ORS 757.649, 2021 Senate Bill 762, ORS 756.040, ORS 756.105 & ORS 757.035
History:
PUC 6-2022, amend filed 09/22/2022, effective 09/22/2022

PUC 2-2022, renumbered from 860-300-0002, filed 02/24/2022, effective 02/24/2022
PUC 10-2021, adopt filed 12/01/2021, effective 12/01/2021

860-300-0030
Risk Analysis

(1) The Public Utility must include in its Wildfire Mitigation Plan risk analysis that describes wildfire risk within the Public Utility's service territory and outside the service territory of the Public Utility but within the Public Utility's right of way for generation and transmission assets. The risk analysis must include, at a minimum:

(a) Defined categories of overall wildfire risk and an adequate discussion of how the Public Utility categorizes wildfire risk. Categories of risk must include, at a minimum:

(A) Baseline wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple years. Examples include topography, vegetation, utility equipment in place, and climate;

(B) Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year or from year to year; Examples include cumulative precipitation, seasonal weather conditions, current drought status, and fuel moisture content;

(C) Risks to residential areas served by the Public Utility; and

(D) Risks to substation or powerline owned by the Public Utility.

(b) a narrative description of how the Public Utility determines areas of heightened risk of wildfire using the most updated data it has available from reputable sources.

(c) a narrative description of all data sources the Public Utility uses to model topographical and meteorological components of its wildfire risk as well as any wildfire risk related to the Public Utility's equipment.

(A) The Public Utility must make clear the frequency with which each source of data is updated; and

(B) The Public Utility must make clear how it plans to keep its data sources as up to date as is practicable.

(d) The Public Utility's risk analysis must include a narrative description of how the Public Utility's wildfire risk models are used to make decisions concerning the following items:

(A) Public Safety Power Shutoffs

(B) Vegetation Management;

(C) System Hardening;

(D) Investment decisions; and

(E) Operational decisions.

(e) For updated Wildfire Mitigation Plans, the Public Utility must include a narrative description of any changes to its baseline wildfire risk that were made relative to the previous plan submitted by the utility, including the Public Utility's response to changes in baseline wildfire risk, seasonal wildfire risk, and Near-term Wildfire Risk.

(2) To the extent practicable, the Public Utility must confer with other state agencies when evaluating the risk analysis included in the Public Utility's Wildfire Mitigation Plan.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 757.035
History:
PUC 6-2022, adopt filed 09/22/2022, effective 09/22/2022

860-300-0040
Wildfire Mitigation Plan Engagement Strategies

(1) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Mitigation Plan Engagement Strategy. The Wildfire Mitigation Plan Engagement Strategy will describe the utility's efforts to engage and collaborate with Public Safety partners and Local Communities impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum:

(a) Accessible forums for engagement and collaboration with Public Safety Partners, Local Communities, and customers in advance of filing the Wildfire Mitigation Plan. The Public Utility should provide, at minimum:

(A) One public information and input session hosted in each county or group of adjacent counties within reasonable geographic proximity and streamed virtually with access and functional needs considerations; and

(B) One opportunity for engagement strategy participants to submit follow-up comments to the public information and input session.

(b) A description of how the Public Utility designed the Wildfire Mitigation Plan Engagement Strategy to be inclusive and accessible, including consideration of multiple languages and outreach to access and functional needs populations as identified with local Public Safety Partners.

(2) The Public Utility must include a plan for conducting community outreach and public awareness efforts in its Wildfire Mitigation Plan. It must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities.

(a) The community outreach and public awareness efforts will include plans to disseminate informational materials and/or conduct trainings that cover:

(A) Description of PSPS including why one would need to be executed, considerations determining why one is required, and what to expect before, during, and after a PSPS;

(B) A description of the Public Utility's wildfire mitigation strategy;

(C) Information on emergency kits/plans/checklists;

(D) Public Utility contact and website information.

(b) In formulating community outreach and public awareness efforts, the Wildfire Mitigation Plan will also include descriptions of:

(A) Media platforms and other communication tools that will be used to disseminate information to the public;

(B) Frequency of outreach to inform the public;

(C) Equity considerations in publication and accessibility, including, but not limited to:

(i) Multiple languages prevalent to the area;

(ii) Multiple media platforms to ensure access to all members of a Local Community.

(3) The Public Utility must include in its Wildfire Mitigation Plan a description of metrics used to track and report on whether its community outreach and public awareness efforts are effectively and equitably reaching Local Communities across the Public Utility's service area.

(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the Public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specified in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0050. The Coordination Strategy should include, at a minimum:

(a) Meeting frequency and location determined in collaboration with Public Safety Partners;

(b) Tabletop Exercise plan that includes topics and opportunities to participate;

(c) After action reporting plan for lessons learned in alignment with Public Safety Partner after action reporting timeline and processes.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 757.035
History:
PUC 6-2022, adopt filed 09/22/2022, effective 09/22/2022

860-300-0050
Communication Requirements Prior, During, and After a Public Safety Power Shutoff (PSPS)

(1) When a Public Utility determines that a PSPS is likely to occur, it must deliver notification of the PSPS to its Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.

(a) To the extent practicable, the Public Utility must provide priority notification directly to Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.

(b) In notifying Public Safety Partners and utility-identified critical facilitates of PSPS events, including adjacent local Public Safety Partners, the utility will communicate the following information, at a minimum:

(A) The PSPS zone, which would include Geographic Information System shapefile(s) depicting current boundaries of the area subject to de-energization;

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

(D) Number of customers impacted by PSPS;

(E) When feasible, the Public Utility will support Local Emergency Management efforts to send out emergency alerts;

(F) At a minimum, status updates at 24-hour intervals until service has been restored;

(G) Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and

(H) Information provided under this rule does not preclude the Public Utility from providing additional information about execution of the PSPS to its Public Safety Partners.

(c) In notifying utility-identified critical facilities, the Public Utility will communicate the following information, at a minimum:

(A) Date and time PSPS will be executed;

(B) Estimated duration of PSPS;

(C) At a minimum, status updates at 24-hour intervals until service has been restored;

(D) Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and

(E) In addition to the above requirements, utilities will also provide Geographical Information Files with as much specificity as possible to Operators of Communications facilities in the area of the anticipated PSPS.

(d) ESF-12 will notify Oregon Emergency Response System (OERS) partners and Local Emergency Management in coordination with Oregon's Office of Emergency Management.

(2) When a Public Utility determines that a PSPS is likely to occur, the Public Utility must provide advance notice of the PSPS to customers via a PSPS web-based interface on the Public Utility's website and other media platforms, and may communicate PSPS information directly with customers consistent with this rule.

(a) In providing notice to customers about a PSPS, the Public Utility will, at a minimum:

(A) Utilize multiple media platforms to maximize customer outreach, including but not limited to, social media, radio, television, and press releases;

(B) Consider the geographic and cultural demographics of affected areas, including but not limited to broadband access, languages prevalent within the utility's service territories, considerations for those who are vision or hearing impaired; and

(C) Display on its website homepage a prominent link to access current information about the PSPS, consistent with OAR 860-300-0060, including a depiction of the boundary. The PSPS information must be easily readable and accessible from mobile devices.

(b) The Public Utility may directly notify its customers through email communication or telephonic notification (*e.g.*, text messaging and phone calls) when it will not impede Local Emergency Management alerts due to capacity limitations. If the Public Utility provides direct notification, the Public Utility will communicate the following information, at a minimum:

(A) A statement of impending PSPS execution, including an explanation of what a PSPS is and the risks that the PSPS would be mitigating;

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

(D) A 24-hour means of contact customers may use to ask questions or seek information;

(E) How to access details about the PSPS via the Public Utility's website, including education and outreach materials disseminated in advance of the annual wildfire season;

(F) After initial notification, the Public Utility will provide, at a minimum, status updates at 24-hour intervals until the conditions prompting the PSPS have ended; and

(G) Notice of when re-energization efforts will begin and when re-energization is expected to be complete.

(3) To the extent possible, the Public Utility will adhere to the following minimum notification prioritization and timeline in advance of a PSPS:

(a) 48-72 hours in advance of anticipated de-energization, priority notification to Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners;

(b) 24-48 hours in advance of anticipated de-energization, when safe: secondary notification to all other affected customers; and

(c) 1-4 hours in advance of anticipated de-energization, if possible: notification to all affected customers.

(4) The Public Utility's communications required under this rule do not replace emergency alerts initiated by local emergency response.

(5) Nothing in this rule prohibits the Public Utility from providing additional information about execution of the PSPS to Public Safety Partners, utility-identified critical facilities, or customers.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 757.035
History:
PUC 4-2022, adopt filed 05/24/2022, effective 05/24/2022

860-300-0060
Ongoing Informational Requirements for Public Safety Power Shutoffs (PSPS)

(1) The Public Utility will create a web-based interface that includes real-time, dynamic information on location, de-energization duration estimates, and re-energization estimates. The web-based interface will be hosted on the Public Utility's website and must be accessible during a PSPS event. The Public Utility will complete the web-based interface before March 31, 2024.

(2) The Public Utility will make its considerations when evaluating the likelihood of a PSPS publicly available on its website. These considerations include, but are not limited to: strong wind events, other current weather conditions, primary triggers in high risk zones that could cause a fire, and any other elements that define an extreme fire hazard evaluated by the Public Utility.

(3) The Public Utility will ensure that its website has the bandwidth capable of handling web traffic surges in the event of a Public Safety Power Shutoff.

(4) The Public Utility will work to provide real-time geographic information pertaining to PSPS outages compatible with Public Safety Partner GIS platforms.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 757.020
History:
PUC 4-2022, adopt filed 05/24/2022, effective 05/24/2022

860-300-0070
Reporting Requirements for Public Safety Power Shutoffs (PSPS)

(1) The Public Utility is required to file annual reports on de-energization lessons learned, providing a narrative description of all PSPS events which occurred during the fire season. Reports must be filed no later than December 31st of each year.

(2) Non-confidential versions of the reports required under this section must also be made available on the Public Utility's website.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 757.035
History:
PUC 4-2022, adopt filed 05/24/2022, effective 05/24/2022

860-300-0080
Cost Recovery

All reasonable operating costs incurred by, and prudent investments made by, a Public Utility to develop, implement, or operate a Wildfire Protection Plan are recoverable in the rates of the Public Utility from all customers through a filing under ORS 757.210 to 757.220.

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 759 & ORS 757
Statutes/Other Implemented: ORS 757.020 & 2021 Senate Bill 762
History:
PUC 2-2022, renumbered from 860-300-0003, filed 02/24/2022, effective 02/24/2022
PUC 10-2021, adopt filed 12/01/2021, effective 12/01/2021

860-300-0090
Consumer-owned Utility Plans

Municipal electric utilities, people's utility districts organized under ORS chapter 261 that sell electricity, and electric cooperatives organized under ORS chapter 62 must file with the Commission a copy of its approved risk-based wildfire mitigation plan or plan update within 30 days of approval from its governing body.

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 759 & ORS 757
Statutes/Other Implemented: ORS 757.035 & 2021 Senate Bill 762
History:
PUC 2-2022, renumbered from 860-300-0004, filed 02/24/2022, effective 02/24/2022
PUC 10-2021, adopt filed 12/01/2021, effective 12/01/2021

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

December 29, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2207(1)—PacifiCorp's 2023 Wildfire Mitigation Plan

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing with the Public Utility Commission of Oregon its 2023 Wildfire Mitigation Plan.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, OR 97232 Email: oregondockets@pacificorp.com	Ajay Kumar Senior Attorney PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, OR 97232 Email: ajay.kumar@pacificorp.com

Additionally, PacifiCorp requests that all formal information requests regarding this matter be addressed to:

By email (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Cathie Allen, Manager, Regulatory Affairs, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Oregon Wildfire Mitigation Plan

2023

PACIFIC POWER

POWERING YOUR GREATNESS

Plan Contents

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Introduction

Due to the growing threat of wildfire in the western United States, Pacific Power has developed a comprehensive plan for wildfire mitigation efforts in all of its service territories. Similar to Pacific Power's 2022 Oregon Wildfire Protection Plan (WPP),[1] this 2023 Oregon Wildfire Mitigation Plan (WMP) guides the mitigation strategies that will be or are currently being deployed in Oregon. These efforts are designed to reduce the probability of utility related wildfires, as well as to mitigate the damage to Pacific Power facilities because of wildfire.

Wildfire has long been an issue of notable public concern. Electric utilities have always needed to be concerned with the potential of a fire starting because of sparks that could be emitted from an electrical facility, generally during a fault condition. The growth of wildfire size and intensity have magnified these concerns. Regardless of the causes, or political debates surrounding the issue, the reality is stark. Despite effective fire suppression agencies and increased suppression budgets, wildfires have grown in number, size and intensity. Increased human development in the wildland-urban interface, the area where people (and their structures) are intermixed with, or located near, substantial wildland vegetation has increased the probability and exacerbated the costs of wildfire damage in terms of both harm to people and property damage. A wildfire in an undeveloped area can have ecological consequences – some positive, some negative – but a wildfire in an undeveloped area will not, generally, directly affect large numbers of people. A wildfire engulfing a developed area, on the other hand, can have significant consequences on people and property. For all of these reasons, Pacific Power is committed to making long-term investments to reduce the risk of wildfire.

The measures in this WMP describe those investments to construct, maintain and operate electrical lines and equipment in a manner that will minimize the risk of wildfire. In evaluating

[1] Per formal rulemaking and OAR 860-300-0020, the Wildfire Protection Plan (WPP) is now referred to as the Wildfire Mitigation Plan (WMP).

which engineering, construction and operational strategies to deploy, Pacific Power was guided by the following core principles:

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.
- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to shorten the duration to isolate the fault event.
- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.

A successful plan must also consider the impact on Oregon customers and Oregon communities, in the overall imperative to provide safe, reliable, and affordable electric service.

Pacific Power's first Oregon WMP, filed on December 30, 2021, consistent with Oregon Administrative Rule (OAR) 860-300-0002,[2] was approved by the Commission with direction to consider recommendations[3] in Order No. 22-131 made effective on April 28, 2022. Consistent with this plan, Pacific Power invested approximately $20.3 million in capital and $32.9 million of expense in 2022 to further many of the company's wildfire mitigation strategies, including:

- Procurement of new risk modeling tools, datasets, and software;
- Installation of 86 incremental weather stations;
- Implementation of increased asset inspections, enhanced asset inspections, and accelerated condition correction;

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[2] OAR 860-300-002 was established per Administrative Order No. 21-440 on December 1, 2021 to facilitate plan development and filing in 2021 consistent with Section 3(2)(a)-(h), chapter 592[2], Oregon Laws 2021. OAR 860-300-002 has since been renumbered and superseded by permanent rules in OAR 860-300-0020, per Order No. 22-131 effective April 28, 2022.

[3] Staff recommendations are included in Appendix B – Adherence to Requirements.

- Transition to a 3 year vegetation management distribution cycle;
- Inspection of 1,700 additional miles, trimming of 18,600 additional trees, removal of over 22,700 additional trees (including brush equivalent), and radial clearing of over 20,000 poles;
- Engineering and design of approximately 91 miles of covered conductor;
- Replacement of approximately 1,000 expulsion fuses and other expulsion equipment with non-expulsion designs;
- Upgrade of 62 relays and reclosers for enhanced functionality;
- Completion of public safety partner engagement and 4 PSPS planning sessions;
- Execution of 5 Oregon WMP public engagement forums; and
- Successful implementation of the company's first PSPS in Oregon.

Pacific Power's 2023 WMP incorporates the company's 2022 experience as well as feedback and recommendations from Commission staff, stakeholders, and communities. As a result, the 2023 WMP includes an investment of approximately $610 million, or $440 million capital and $170 million expense, over the next 5 years, with an expectation of continued, additional investment beyond 2027. Section 13 - Plan Summary, Costs, & Benefits includes a summary of all plan elements, forecasted costs, and anticipated benefits.

The strategies embodied in this plan are evolving and are subject to change. As new analyses, technologies, practices, network changes, environmental influence or risks are identified, changes to address them may be incorporated into future iterations of the plan as described in Section 12, Plan Monitoring & Implementation.

1. Risk Modeling and Drivers

1.1 BASELINE WILDFIRE RISK

Pacific Power's areas of heighted risk of wildfire, which are expected to remain fixed for multiple years, are grouped together and referred to as the "FHCA" or Fire High Consequence Area.

The FHCA was determined in collaboration with REAX engineering, a consultant specializing in wildland fire computer modelling, and is grounded in 30 years of historic meteorological and fire weather data. The FHCA map identified through the methodology described in the following subsections, functions as Pacific Power's baseline risk assessment and sets the geographical boundaries for current wildfire programs such as asset inspections, vegetation management, and prioritized system hardening. The geographic boundaries of the FHCA are synonymous with the boundaries of Pacific Power's designated High Fire Risk Zones (HFRZs). For brevity in reference and consistency with internal usage, this WMP uses the term "FHCA." In terms of compliance with the High Fire Risk Zone Safety Standards in OAR 860-024-0018, however, Pacific Power stresses that the geographic boundaries of the FHCA and the High Fire Risk Zones (HFRZs) are the same.

Scope

Pacific Power's analysis of baseline wildfire risk in Oregon was a part of a larger, multi-state[4] effort in 2018 and 2019 patterned after the methodology developed through a multi-year, iterative process in California. To take advantage of the company's experience gained in

[4] PacifiCorp, d/b/a Pacific Power in Oregon, Washington and California, provides electric service to customers in Oregon, Washington, California, Utah, Idaho, and Wyoming. The risk modeling assessment described in this section was made across all PacifiCorp states.

California, Pacific Power engaged fire-science engineering firm REAX Engineering to identify areas of elevated fire risk, which were ultimately designated with the name of FHCA.

To accomplish this, Pacific Power and REAX first identified the general geographic areas subject to the risk analysis, which included Pacific Power's service territory and a 25-mile study area around all Pacific Power-owned transmission lines, as depicted below. The scope is inclusive of Pacific Power's service territory and outside the service territory within the right of way for generation and transmission assets.

Figure 1: Study Area to Determine FHCA

General Methodology

Pacific Power's baseline risk evaluation process employs the concept that risk is the product of the likelihood of a specific risk event multiplied by the impact of the event, also referred to as risk consequence. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of an event is an estimate of the effect to people and property when an event occurs. Impact can be evaluated using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, the company's image and reputation, and financial implications. As discussed below, the risk analysis in this plan focuses on the potential impact in terms of harm to people and damage to property.

Pacific Power's baseline risk analysis evaluates topography, fuel data, climatology, historic fire weather days, live fuel moisture estimates, and presence of structures to identify the geographic areas in Pacific Power's service territory at the greatest risk of wildfire, should an ignition occur, as depicted in the diagram below.

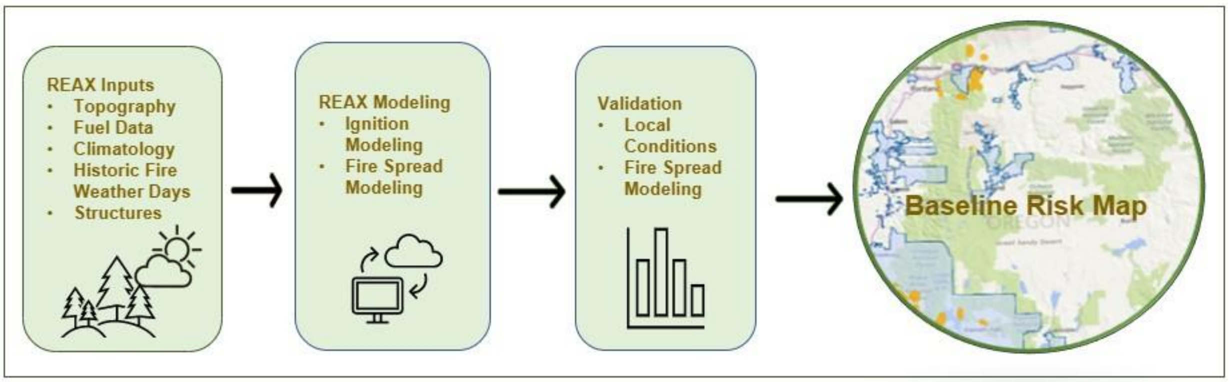


Figure 2: Methodology for Baseline Risk Map

REAX conducted the wildfire risk analysis on the scoped area using multiple datasets, data sources, and processes, which generally included wind/weather inputs from WRF (Weather Research and Forecasting); the fire spread analysis also applied topography, fuel data, and structure density. In completing the analysis, REAX used the following inputs:

1. Topography of the land, including elevation, slope and aspect
2. Fuel data (from a dataset known as LANDFIRE[5]) with 30 m pixel resolution were used to quantify surface fuel loading, particle size, and other quantities needed by fire models using the "Scott and Burgan 40" Fire Behavior Fuel Models.

[5] See https://www.landfire.gov/datatool.php

3. Weather Research and Forecasting (WRF), resulting in climatology derivative from North American Regional Reanalysis (NARR) with resolution at 32 km, which is a hybrid of weather modeling and surface weather observations (including temperature, relative humidity, wind speed/direction, and precipitation, weather balloon observations of wind speed/direction and atmospheric, sea surface temperatures from buoys, satellite imagery for cloud cover and precipitation).[6]
4. Historic fire weather days spanning the period from January 1, 1979, through December 31, 2017.
5. Estimated live fuel moisture from the United States Forest Service (USFS).
6. Ignition modeling, using Monte Carlo-simulated ignition scenarios.
7. Fire spread modeling, Eulerian Level Set Model for Fire Spread (ELMFIRE).

Table 1: Inputs to FHCA Map

FHCA Map Input	Data Source	Resolution
TOPOGRAPHY	2017 LANDFIRE 1.4.0 database release	30 m
FUEL DATA	2014 LANDFIRE - "Scott and Burgan 40" Fire Behavior Fuel Models dataset	30 m pixel resolution
CLIMATOLOGY	2017 release of WRF 5 Year Data (updated daily from 1979)	3 km
HISTORIC FIRE WEATHER DAYS	NARR (January 1, 1979 – December 31, 2017)	32 km

[6] Essentially, a weather model similar to WRF assimilates/ingests several thousand weather observations over a three-hour period and then uses that information to create a 3D representation of the atmosphere every three hours. This includes not only surface (meaning near ground level) quantities but also upper atmosphere quantities as well. The NARR dataset is available from 1979 (when modern satellites first became available) to current day (with a lag of a few weeks).

FHCA Map Input	Data Source	Resolution
STRUCTURE DENSITY	2010 US CENSUS Data	30 m
ASSET LOCATION	Pacific Power GIS file	25 mile

These key data inputs were then processed using Monte-Carlo simulations, a computerized mathematical technique used to predict the probability of different outcomes, and the ELMFIRE model, an established wildland fire spread model and software, to evaluate the potential severity of fire spread that could exist associated with a wide range of potential ignition events across Pacific Power's service territory. This process runs thousands of simulations using these inputs and spread algorithms, assumes a six hour burn period, and leverages fire type, flame length, and nearby structures to quantify the potential fire size (acres), volume, (acre-ft) and impact (number of structures). After REAX completed this analysis, the fire maps were then analyzed by Pacific Power to create the FHCA maps.

Through this process, individual blocks of geographic area, each a 2-kilometer square cell, received a grid score corresponding to its relative wildfire risk. The outputs of the prior Pacific Power California mapping project were used for calibration and assigned grid cell scores in Oregon correlating with California statewide grid cell scores. This approach enabled an "apples-to-apples" comparison to the results of that prior project so that the relative degree of wildfire risk in areas of other states could be compared to the risk in areas of California. The Geographic Information System (GIS) software algorithm "Jenks natural breaks" was then applied to segment areas into 33 families of risk areas[7] so that all cell areas were given a score from 0 to 32. In this model, cell values do not imply direct mathematical relationships, but rather indicate groupings of relative wildfire risk, where the risk is evaluated relative to other areas within Pacific Power's territory. After completion of the computer modeling, a

[7] See https://www.spatialanalysisonline.com/extractv6.pdf

validation activity was completed by evaluating historic fire perimeters, existing Pacific Power facility equipment, and local conditions.

FHCA Map (High Fire Risk Zones)

Based on the methodology described in the previous section, Pacific Power then generated the following map highlighting the FHCA, the geographic locations within Pacific Power's service territory with a heightened risk of wildfire.

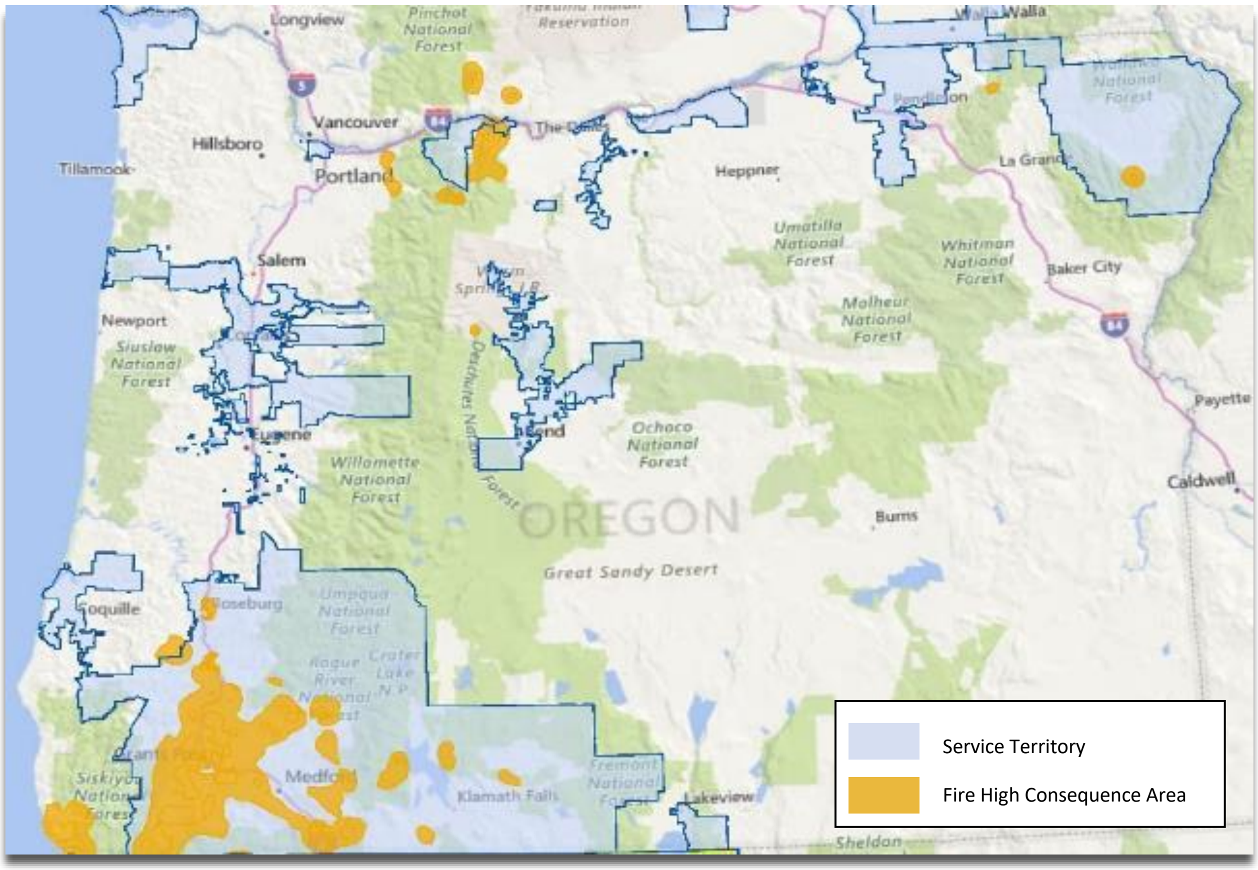


Figure 3: Fire High Consequence Area (FHCA) Map

The FHCA, or baseline risk map, informs targeted investment where multi-year programmatic shifts, such as the increased frequency of asset inspections or the use of enhanced vegetation management practices, can work to mitigate the risk of wildfire. The following table describes the breakdown of Pacific Power overhead assets in the FHCA where many of these targeted strategies are focused.

Table 2: Overhead Asset Inventory in the FHCA

Asset	Total	FHCA	
	Line-Miles	Line-Miles	% Of Total
OH Transmission	3,056	413	14%
57kV Transmission Lines	14	0	0%
69kV Transmission Lines	914	96	10%
115 kV Transmission Lines	999	177	18%
230 kV Transmission Lines	605	90	15%
500 kV Transmission Lines	522	50	10%
OH Distribution	12,890	2,264	18%

Update Frequency

The risk assessment done in consultation with REAX started to inform and guide mitigation planning in 2018, and the company finalized the boundaries of the FHCA in 2019. Pacific Power plans to refresh the analysis on a routine cycle, using the most updated methodologies, tools, and data.

In determining the planned update frequency of baseline risk assessment, Pacific Power considered both the duration of the update itself as well as the intended use of the assessment and impacts to corresponding programs or projects. Because baseline risk assessment is used to inform multi-year programs, such as asset inspections and vegetation management consistent with OAR 860-024-0018, modifying geographic boundaries too frequently would be disruptive to making and tracking progress on these programs. In addition, making an update to baseline risk mapping typically is a multi-year project on its own. Therefore, Pacific Power plans to refresh baseline risk mapping on a five-year cycle, consistent with the detailed inspection cycle described in Section 3. See figure below.

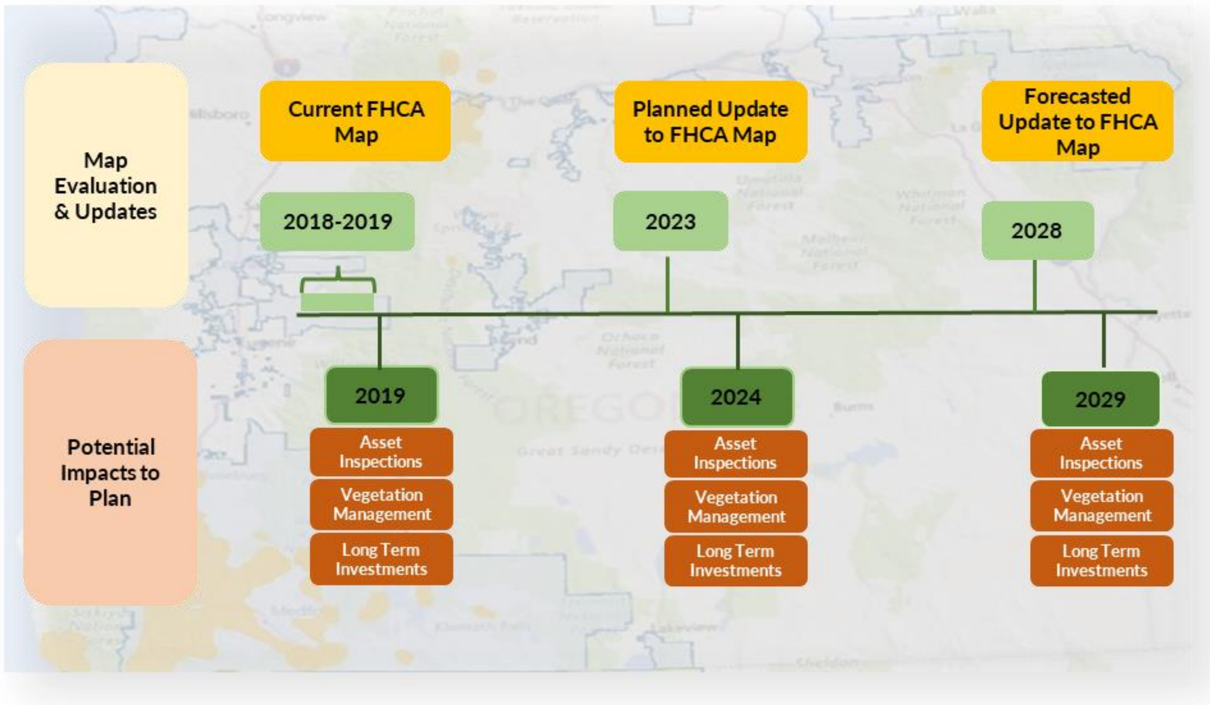


Figure 4: Baseline Risk Assessment Update Frequency

While the planned five-year cycle is intended to set expectations for a refreshed analysis and facilitate continuous improvement, Pacific Power intends to monitor trends, data, and industry best practices. If an off-cycle modification is appropriate, Pacific Power may refresh the baseline risk assessment more or less often than the 5-year cycle described above.

Prioritized Areas for Hardening

Approximately 18% of the company's overhead assets in Oregon are located in the FHCA, which includes approximately 2,700 miles of overhead distribution and transmission lines spread across nearly 3,000 square miles. While certain programs such as asset inspections or vegetation management can be scaled and applied broadly across the entire FHCA, multi-year, long-term investments such as grid hardening require further prioritization.

To pinpoint the areas of most extreme risk for prioritized investment, Pacific Power examined the FHCA overlaid with typical fire weather patterns to identify locations within the FHCA where significant fire escalation potential exists due to wind patterns, vegetation, and population. These areas are generally depicted below.

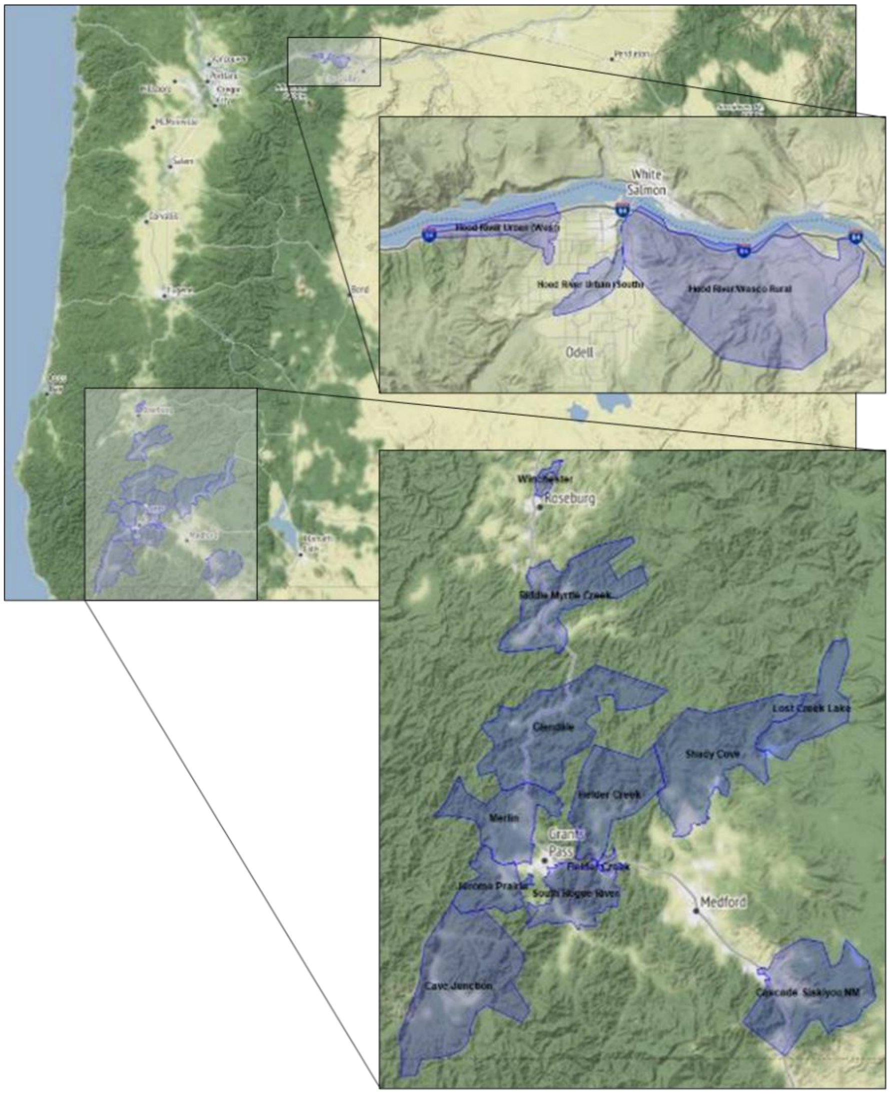


Figure 5: Prioritizes Areas for Long Term Investment

Circuits within these areas were then prioritized based on geographic location, outage and ignition history, fire weather history, population and property at risk due to an ignition, and efficiency in planning and execution.

As a result, 85 overhead miles on (5) circuits were identified for engineering, design, and construction in 2022-2023. These projects were moved through the line rebuild project pipeline as described and depicted in Section 4. Similarly, system automation projects were prioritized and moved through construction pipelines as discussed in Section 4.2.

While Pacific Power has identified prioritized circuits and projects for 2022-2023 based on the existing risk analysis, the company is investing in new tools and software to inform future project selection and prioritization as discussed in Section 1.4. Additionally, the company is also forecasting continued investment and projects beyond 2023 which is reflected in Sections 4 and 13 accordingly.

1.2 IDENTIFICATION OF RISK DRIVERS

While risk mapping identifies geographic locations with a heightened level of baseline wildfire risk, Pacific Power also analyzes the components of risk associated with utility facilities. In particular, an understanding of risk drivers informs specific mitigation tactics or strategies that can be used to reduce the total amount of risk associated with utility operations. For example, if the risk of utility related wildfire exists due to the potential for equipment failure, an increase in inspections or maintenance activities can help to mitigate the risk. If the risk exists due to potential contact with third party objects, constructing a system more resilient to contact with objects can help to mitigate the risk.

In determining the potential risk drivers, Pacific Power leveraged a data driven approach that analyzed certain categories of historical outage records as a proxy for risk events. Outage data is the best available data to correlate an identifiable event on the electrical network to the risk of a utility related wildfire. There is a logical physical relationship: when a fault creates a spark, there is a risk of fire. An unplanned outage – which is when a line is unintentionally de-energized – is most often rooted in a fault. Accordingly, the company has closely analyzed the causes and frequency of outages. This analysis is leveraged to determine which wildfire mitigation programs and protocols are best suited to minimize fault events, thereby reducing the risk of fire.

Pacific Power maintains outage records in the normal course of business as part of Pacific Power's efforts to assess service reliability. These records document the location, duration, and causes of outages. To understand key risk drivers, these outage records were organized into categories to understand the probability of each outage cause with the potential to cause an ignition. These categories are included in the table below. Additional outage categories, such as loss of upstream transmission supply, planned outage, or not an outage (misclassification), do not indicate the potential for an ignition and, therefore, were not included in this table.

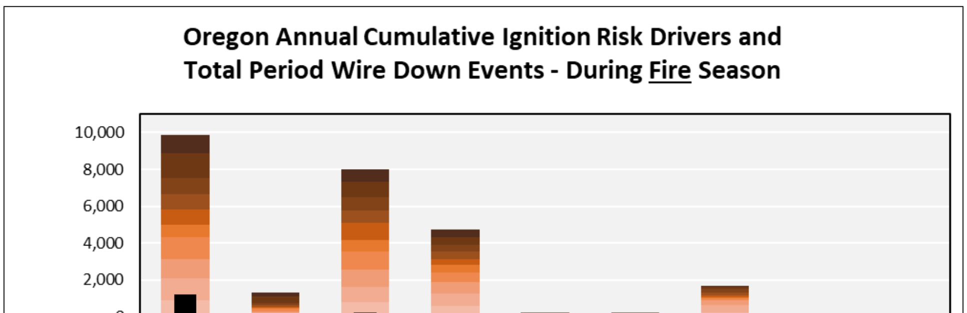
Table 3: Outage Causes with Possible Correlation to Ignition Potential

Outage Category[8]	Description
ANIMALS	Animals making unwanted direct contact with energized assets.
ENVIRONMENT	Exposure to environmental factors, such as contamination
EQUIPMENT DAMAGED	Broken equipment from car hit-poles, vandalism or other non-lightening weather- related factors.
EQUIPMENT FAILURE	Failure of energized equipment due to normal deterioration and wear, such as a cross arm that has become cracked or the incorrect operation of a recloser, circuit breaker, relay, or switch
LIGHTNING	Outage event directly caused by lightning striking either (i) energized utility assets or (ii) nearby vegetation or equipment that, as a result, makes contact with energized utility assets
OTHER EXTERNAL INTERFERENCE	External factors not relating to damaged equipment such as mylar balloons, hay or other interference resulting in a potential ignition source
NOT CLASSIFIABLE	Outage event with unknown cause or multiple potential possible causes identified
OPERATIONAL	Outage event resulting from improper operating practice or other human error

[8] Outage categories align with potential correlation to an ignition and may not necessarily match the outage classification used by field employees.

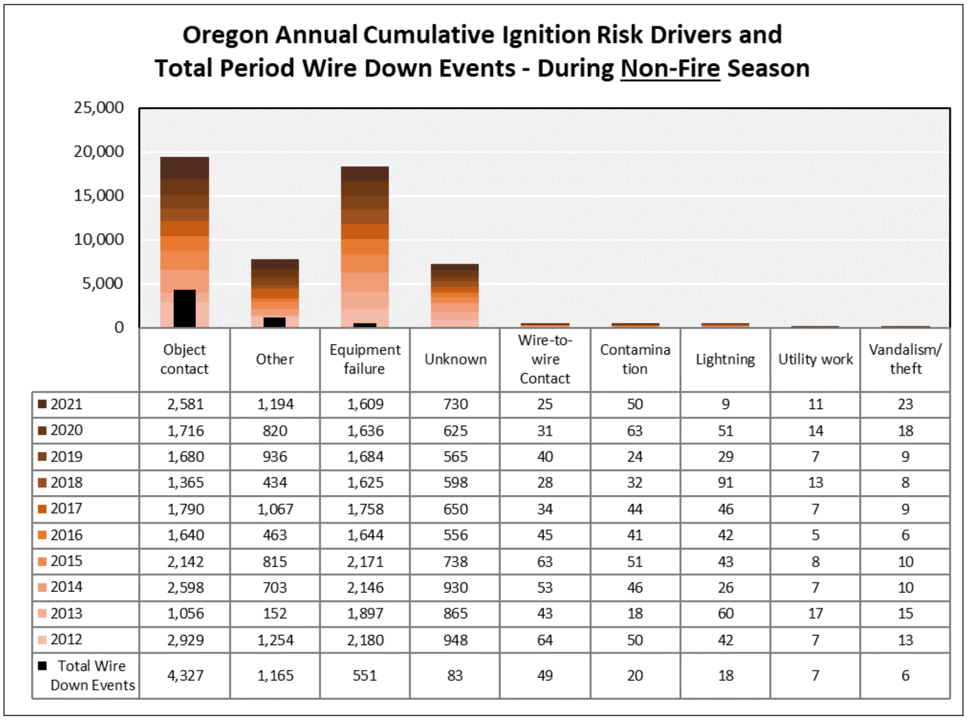
Outage Category[8]	Description
TREE-PREVENTABLE	Outage attributed to vegetation condition which should have been remedied during regular cycle maintenance under the company's vegetation management program
TREE-OUTSIDE PROGRAM	Outage attributed to vegetation condition not managed under the company's vegetation management program

Using these ten outage categories, Pacific Power performed a seven year look back in the outage records and focused specifically on outages occurring during fire season (June 1 through October 1). Because "wire down" events are the situation most likely to ignite ground fuels, tracking and diagnosing components which are involved in wire down events is important. For this reason, wire down event data is overlaid in Figure 6 and Figure 7 below.



	Object contact	Other	Equipment failure	Unknown	Wire-to-wire Contact	Contamination	Lightning	Utility work	Vandalism/ theft
2021	1,016	164	682	394	11	32	61	6	9
2020	1,330	370	815	427	17	20	113	3	9
2019	876	93	768	367	22	16	204	2	3
2018	844	104	674	413	12	11	134	0	3
2017	823	69	900	330	11	17	135	4	4
2016	668	55	635	379	17	19	16	8	2
2015	1,173	153	961	528	25	31	137	5	4
2014	1,072	68	939	642	26	22	235	3	7
2013	1,175	154	867	669	42	12	424	7	8
2012	895	52	772	576	20	9	222	8	9
Total Wire Down Events	1,184	107	237	64	32	13	62	1	4

Figure 6: Historic Ignition Risk Drivers During Fire Season



	Object contact	Other	Equipment failure	Unknown	Wire-to-wire Contact	Contamination	Lightning	Utility work	Vandalism/ theft
2021	2,581	1,194	1,609	730	25	50	9	11	23
2020	1,716	820	1,636	625	31	63	51	14	18
2019	1,680	936	1,684	565	40	24	29	7	9
2018	1,365	434	1,625	598	28	32	91	13	8
2017	1,790	1,067	1,758	650	34	44	46	7	9
2016	1,640	463	1,644	556	45	41	42	5	6
2015	2,142	815	2,171	738	63	51	43	8	10
2014	2,598	703	2,146	930	53	46	26	7	10
2013	1,056	152	1,897	865	43	18	60	17	15
2012	2,929	1,254	2,180	948	64	50	42	7	13
Total Wire Down Events	4,327	1,165	551	83	49	20	18	7	6

Figure 7: Historic Ignition Risk Drivers During Non-Fire Season

Information from these ignition risk drivers helps shape Pacific Power's programs which typically focus on methods, tactics, and technologies that reduce outages or, more specifically, fault events. The table below generally maps Pacific Power's key risk drivers to the primary programs included in this plan, demonstrating what elements impact a group or groups of risk drivers. It is important to note that elements may not address a risk driver 100% but are designed to mitigate the risk associated with that driver. Furthermore, for many risk drivers, risk is mitigated through a combination of programs and there is not always a 1:1 relationship between a risk driver category and a mitigation program. All elements and programs in the plan work together to collectively mitigate wildfire risk.

Table 4: Risk Driver Mapping to Potential Mitigation Program(s)

Key Risk Driver	Significant Contributor to Wire Down Events	Potential Mitigation Program Categories				
		Asset Inspections	Vegetation Management	System Hardening	Field Operations	System Operations
Object Contact	X	X	X	X	X	X
Other	X	X	X	X	X	X

Key Risk Driver	Significant Contributor to Wire Down Events	Potential Mitigation Program Categories				
		Asset Inspections	Vegetation Management	System Hardening	Field Operations	System Operations
Equipment Failure	X	X	X	X	X	X
Unknown	X	X	X	X	X	X
Wire-to-wire contact	X	X		X	X	X
Contamination		X		X	X	X
Lightning				X		
Utility Work		X		X	X	X
Vandalism/ Theft		X		X		

Continued Evaluation of Risk Drivers

Pacific Power first performed the risk driver analysis above in 2019 as part of its risk modeling program development and has continued to update the data annually with only a few modifications in the outage classification. For example, to facilitate direct classification of wire-down and wire-to-wire contact fault events, which may have resulted in slight variations in data when compared year over year, a separate category was created to identify these types of events.

It is important to note that the evaluation of risk drivers utilizes the outage data obtained through the Company's outage data collection system which was developed to inform responses to outage events and further analysis for reliability improvement purposes. This data is being re-purposed through this effort to support the process of evaluating ignition probabilities. As a result, certain assumptions related to how this mapping occurred initially may need to be revisited. As Pacific Power's risk modeling efforts evolve, this process and assumptions may be modified to improve the modeling and correlations between outages, risk events and ignition probabilities.

1.3 PROGRAM SELECTION AND PRIORITIZATION

Baseline risk mapping identifies the areas of heightened wildfire risk within Pacific Power's service territory. The evaluation of risk drivers identifies Pacific Power's top key risks and informs what program elements best mitigate these key risks. Once these foundational elements are completed, Pacific Power applies a high-level decision-making process that aligns with many other utilities to develop specific projects or programs, not including compliance driven system wide programs. The high-level process, represented by Figure 8, includes four key phases: (1) risk modeling and assessment, (2) project and project identification, (3) evaluation and selection, and (4) implementation and monitoring. While not specifically shown in the general framework, part of the process allows for a mitigation program to be pushed back to a previous step if needed.

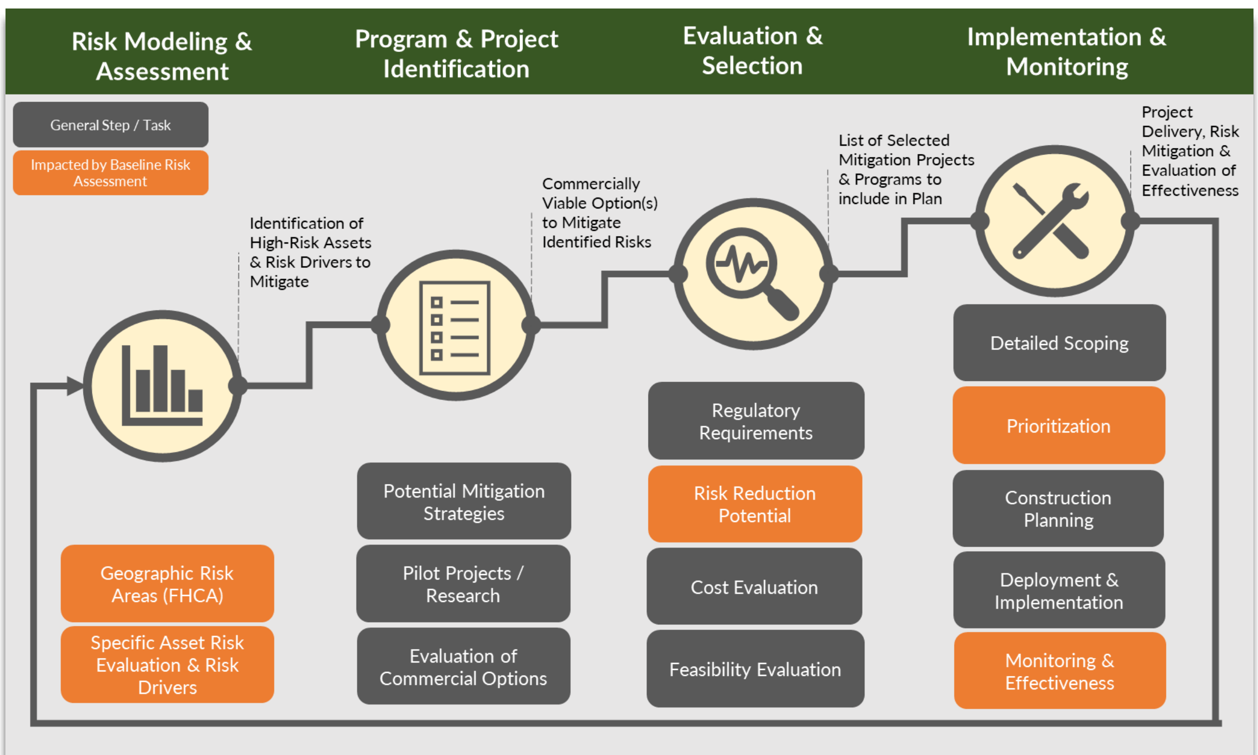


Figure 8: Project and Program Selection High Level Process

Phase 1 – Risk Modeling & Assessment

The decision-making process begins with identifying risk event trends. Pacific Power's outage data identifies the risk events which are then categorized by the risk driver identified for the outage and described in Section 1.2. Once the risk driver has been categorized, the outage data is used to determine the frequency of each risk driver. Initiatives are focused on addressing the frequently occurring risk drivers.

Phase 2 – Program & Project Identification

Identifying mitigation pilots and initiative progression requires an evaluation of current industry practices and technology utilized. Pacific Power also has relationships with other utilities, across multiple states, and discusses industry practices with those utilities, thereby learning from other utility experiences. Pacific Power then evaluates proven industry solutions for selection as a mitigation program.

Phase 3 – Evaluation & Selection

Mitigation initiatives are evaluated for implementation based on a combination of the one or more identified criteria including:

- Commission or regulatory requirements
- Stakeholder and customer input
- Wildfire risk impact
- Customer impact
- Ease of implementation / Constructability
- Project costs

Programs are reviewed and approved by upper management for program planning (scoping, prioritization, design, and implementation).

Phase 4 – Implementation & Monitoring

Scoping. The program scoping reviews the ignition risk driver the program needs to address and reviews other simultaneous programs. Other utilities best practices for implementation are considered to develop a comprehensive scope.

Prioritization. As a general rule, work is prioritized in locations with a higher fire risk. Currently, areas within the FHCA generally have a higher priority than areas outside of the FHCA. Each program is reviewed against simultaneous programs working to address the same risk driver. Programs that mitigate PSPS impact may receive additional prioritization.

Design. After the prioritization has been determined, the program will move to the design stage. The design stage can take on many different forms depending on the project, ranging from schematics and process design to a complete engineering design.

Implementation. Once the scope, prioritization, and design have been completed, the program is ready to be implemented. Prior to implementation various metrics may be determined that will be collected during and after the implementation. The metrics can include installation dates, completion dates, conditions, and outages reported. The data is gathered to assess the program for future revisions in risk modeling.

1.4 BASELINE RISK ASSESSMENT PROJECTS AND IMPROVEMENTS

Through Pacific Power's participation in formal regulatory proceedings, workshops, and multi-state and multi-utility collaborations, the Company has identified three key areas for continued improvement in 2023: (1) Refresh to Baseline Risk Mapping, (2) Project Selection & Prioritization Tool Development, and (3) Advanced Data Analytics Software.

Refresh to Baseline Risk Mapping (FHCA Map Update)

As described in Section 1.1 above, Pacific Power plans to update baseline risk mapping, including data inputs, every 5 years. The company finalized and published the original FHCA map boundaries in 2019. Therefore, Pacific Power plans to implement a project in 2023, to review the methodology, update data sources, and then update the FHCA map boundaries in 2024 as depicted in Figure 9.

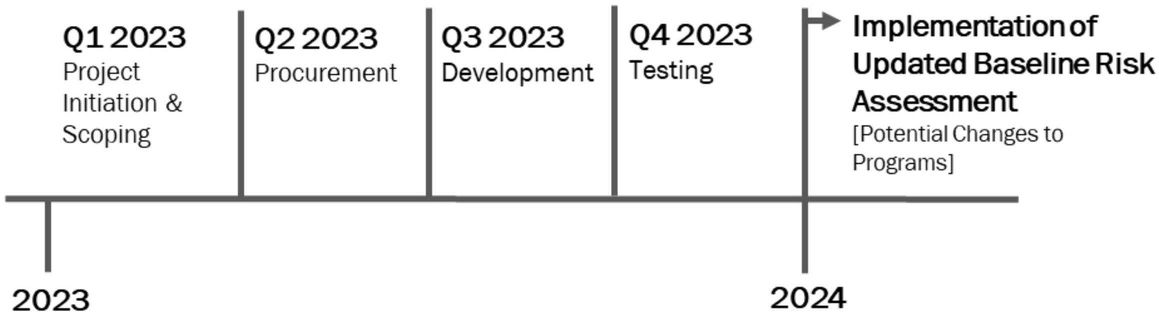


Figure 9: Baseline Risk Mapping (FHCA) Update Timeline

Project Selection & Prioritization Tool Development

Similar to the creation of the FHCA map, current projects were developed and prioritized based on prior risk assessment work. Pacific Power now plans to develop and implement an enterprise supported tool to ensure repeatability, sustainability, and enhanced transparency, in alignment with stakeholder feedback, recommendations from Commission Staff, and sharing of industry best practices with other utilities. Specifically, this new tool will work to incorporate Staff's recommendation to provide quantitative analysis and transparency in project selection and prioritization.[9]

In 2022, Pacific Power procured and began implementation of this new tool, the Wildfire Risk Reduction Model (WRRM), which is a commercially available module in a broader software suite from Technosylva more commonly referred to as Wildfire Analyst (WFA-E). Technosylva has provided advanced wildfire products and services to utilities throughout the United States since 1997 and other modules in WFA-E are used by the California Department of Forestry and Fire Protection (Cal Fire). Technosylva has in-house fire and data scientists, and partners with key providers in fire planning, advanced data modeling, wildland fire research and

[9] See Recommendation 18 in Order No. 22-121 and included in Appendix C – Staff Recommendations which recommends that "Pacific Power include a summary of the quantitative analysis used in the choice and prioritization of specific solutions and investments."

development to enhance the models used in their software. Technosylva has also published studies in scientific journals and wildfire industry publications.

WRRM was built on the quantitative risk model developed by San Diego Gas & Electric (SDG&E) and Technosylva that associates wildfire hazards with the location of electric distribution overhead assets. Once operational, WRRM will be used to forecast the consequence or impact of a wildfire from a given ignition point in Pacific Power's service territory based on the potential spread of a wildfire should it occur. Pacific Power chose to implement WRRM based on Technosylva's experience with other West Coast utilities and their partnership with experts in wildfire and fire data science. The figure below depicts the overall WRRM framework for risk estimation.

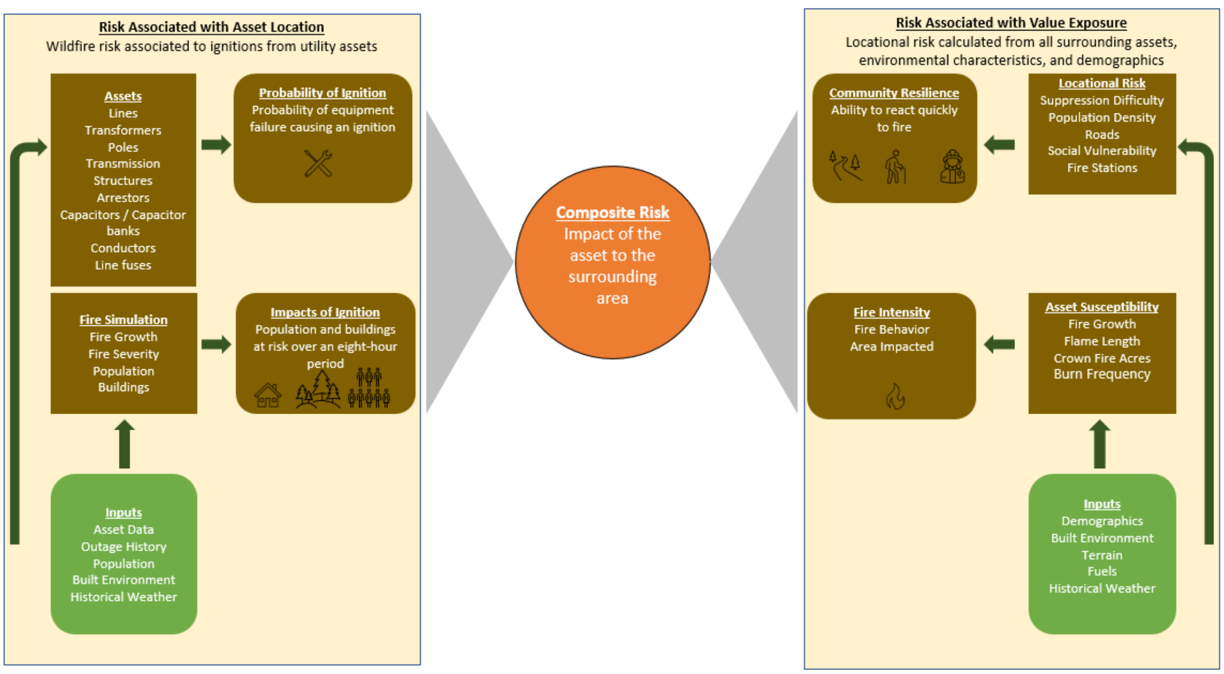


Figure 10: Overall WRRM Framework for Risk Estimates

WRRM uses utility asset information, community characteristics, terrain, vegetation, and weather information to provide a risk score that takes the following into account:

- **Utility asset risk:** Probability of failure, probability of ignition
- **Locational risk:** Population density, buildings, terrain difficulty, egress, road density, and social vulnerability

- **Potential fire behavior:** Size, rate of spread, flame length, crown fire potential

Once implemented, WRRM risk estimates will replace the existing risk data set used in project selection and prioritization. WRRM provides a more comprehensive approach to assessing wildfire impacts by including locational risk and potential fire behavior in addition to the utility asset risk available in risk data currently in use for project selection. As a result, future project selection will be informed by community impacts based on fire spread from an ignition point. By including the consequence of a wildfire ignition from utility assets through WRRM, Pacific Power's wildfire mitigation project selection process will reflect lessons learned from other utilities and industry best practices for wildfire mitigation planning.

The following depicts Pacific Power's forecasted implementation timeline for WRRM.

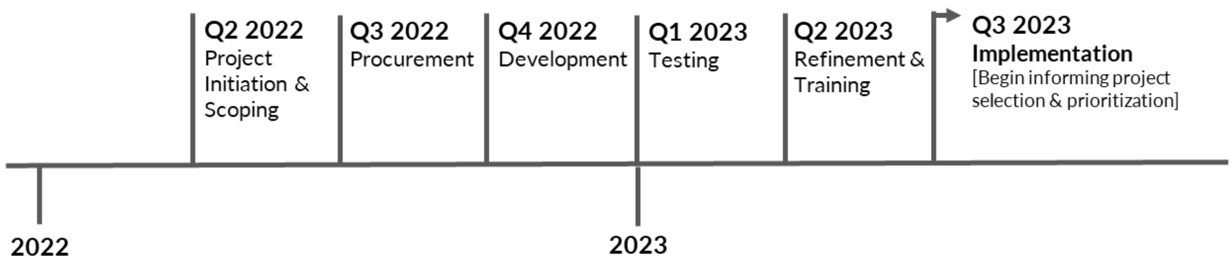


Figure 11: WRRM Implementation Timeline

Advanced Data Analytics Tool

Based on Staff recommendations,[10] Pacific Power is investing in data analytics software beginning in 2023 to begin evaluating the overall effectiveness of mitigation programs, validate risk modeling assumptions and outputs, and enable Risk-Spend Efficiency (RSE) calculations. First, Pacific Power plans to enhance existing data collection processes for fire incident tracking, including ignition data gathering, and outage correlation. Second, Pacific

[10] Staff's recommendations were outlined in Order 22-131 and are included in Appendix C – Staff Recommendations.

Power will also develop a Risk-Spend Efficiency (RSE) model. Both efforts will supplement the WRRM tool described above.

For fire incident tracking, Pacific Power plans to replace its existing file repository with an advanced data analytics platform to enable long-term trend analysis, inform project prioritization, and measure the effectiveness of mitigation programs. The data analytics tool will combine fire incident information with utility asset and outage data (if applicable) to create a comprehensive view of each tracked fire event. Actual fire incident data, including time, location, affected equipment (if any), and burn area size, is critical to WRRM because this data can be used to validate modeled ignition risk and fire spread, update assumptions, and refine calculations. Publicly available historical fire data may also be used for model validation to supplement existing Pacific Power databases.

In addition to providing model validation and detailed incident tracking, the data analytics tool will also be used to evaluate the effectiveness of wildfire mitigation efforts at the program and project levels. The effectiveness model will accomplish two objectives. First, the effectiveness model, combined with estimated project costs, will be used for RSE calculations for project planning beginning in 2023 for selected projects to begin in 2024. Second, the model will enable the evaluation of the risk reduction achieved by completed wildfire mitigation projects to assess overall mitigation program effectiveness.

The effectiveness model will calculate the risk reduction resulting from system hardening or other wildfire mitigation projects in a proposed project site. This will be determined based on how the potential mitigation project addresses risk drivers contributing to elevated wildfire risk in that specific location. An area of active research in utility risk management, Pacific Power is participating in joint working groups with other utilities, government agencies, and wildfire risk experts to implement best practices for accurately modeling mitigation effectiveness. The effectiveness model will be used to enhance existing processes for project selection by incorporating WRRM outputs and the estimated risk reduction of potential wildfire mitigations into a user-friendly analytics platform for use by program managers and project engineers.

Pacific Power will also use the fire incident data analytics tool to evaluate overall wildfire mitigation program effectiveness. By collecting fire incident information in a single database, Pacific Power will be able to identify trends and patterns in wildfires near its equipment. This information can then be used to assess changes to risk drivers over time for inclusion in WRRM and effectiveness models. In addition, the fire incident information will allow Pacific Power to conduct long-term trend analysis of wildfire incidents near its equipment to validate risk model assumptions and outputs and the risk reduction achieved by completed wildfire mitigation projects.

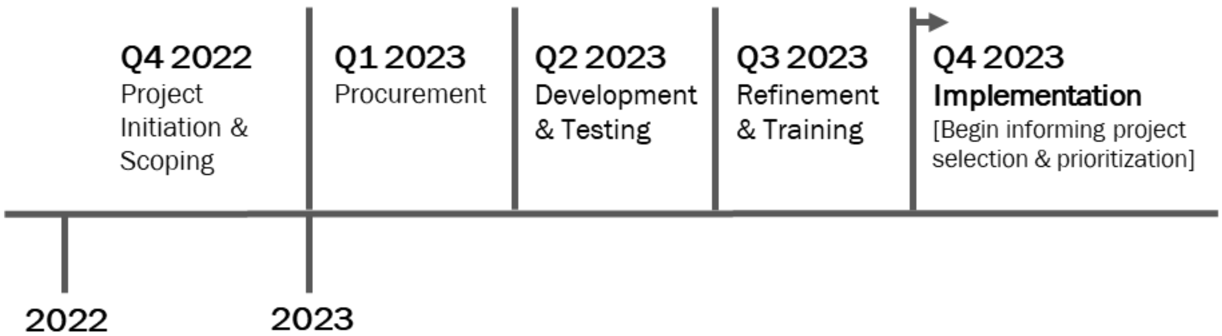


Figure 12: Advanced Data Analytics Project Timeline

1.5 FUTURE BASELINE RISK ASSESSMENT FRAMEWORK

Pacific Power's future baseline risk analysis framework will consist of four main components: (1) the FHCA Map, (2) the WRRM project selection and planning tool, (3) a risk reduction evaluation and prioritization tool, and (4) advanced analytics and effectiveness evaluation. This framework is depicted in Figure 13.

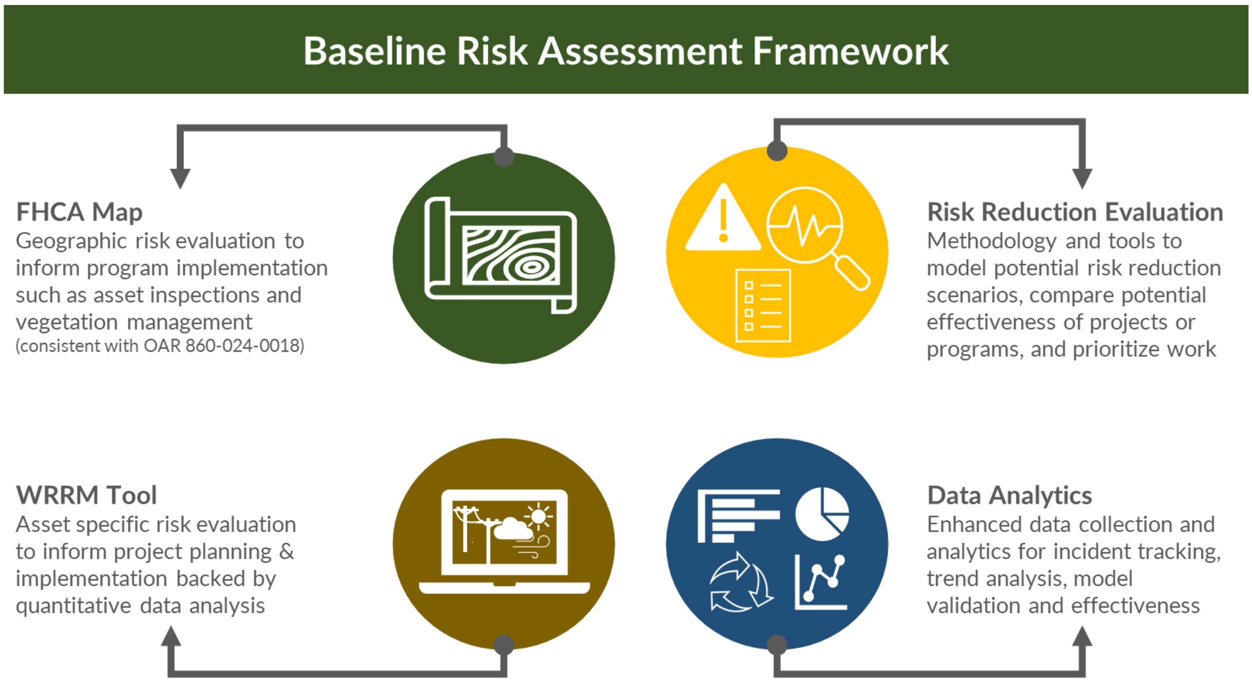


Figure 13: Pacific Power's Future Baseline Risk Assessment Framework

Pacific Power's planned projects and improvements as discussed in Section 1.4 above will have a substantial impact on the company's project and program selection, prioritization, planning, and implementation processes. For example, the planned refresh to the FHCA map will potentially impact programs such as vegetation management and asset inspections beginning in 2024. The WRRM tool will build upon the analysis performed in 2019 and provide a repeatable, transparent way of evaluating projects in long term investment supported by data analytics and modeling beginning in 2023 for projects to be constructed in 2024. And finally, the advanced data analytics software provides for enhanced data collection, analytics, and risk reduction scenario modeling to enhance project prioritization and evaluate program effectiveness beginning in 2023. The image below visually depicts these projects, how these projects will impact Pacific Power's processes, and when these changes will be implemented to evolve the company's framework.

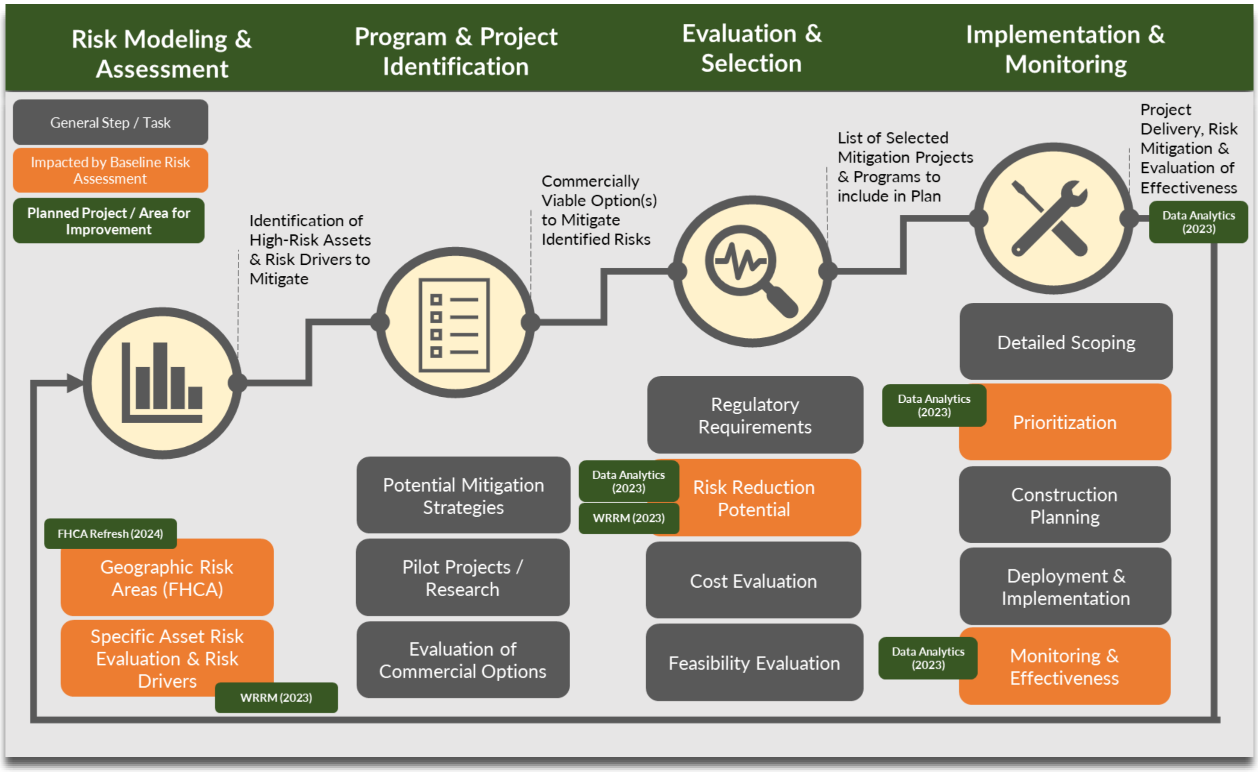


Figure 14: Impacts to Project Selection and Prioritization High Level Process

2. Inspection and Correction

Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions.

Pacific Power performs inspections on a routine basis as dictated by both state-specific regulatory requirements and Pacific Power-specific policies. When an inspection is performed on a Pacific Power asset, inspectors use a predetermined list of condition codes (defined below) and priority levels (defined below) to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, Pacific Power uses condition codes to establish the scope of and timeline for corrective action to maintain conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and Pacific Power specific policies. This process is designed to correct conditions while reducing impact to normal operations.

Key terms associated with Pacific Power's Inspections & Corrections Program are defined as follows:

Detailed Inspection. A careful visual inspection accomplished by visiting each structure, as well as inspecting spans between structures, which is intended to identify potential nonconformance with the NESC or other applicable state requirements, infringement by other utilities or individuals, defects, potential safety hazards, and deterioration of the facilities that need to be corrected to maintain reliable and safe service.

Pole Test & Treat. An inspection of wood poles to identify decay, wear or damage, which may include pole-sounding, inspection hole drilling, and excavation tests to assess the pole condition and identify the need for any repair, or replacement and apply remedial treatment according to policy.

Visual Assurance Inspection. A brief visual inspection performed by viewing each facility from a vantage point allowing reasonable viewing access, which is intended to identify damage or defects to the transmission and distribution system, or other potential hazards or right-of-way-encroachments that may endanger the public or adversely affect the integrity of the electric system, including items that could potentially cause a spark.

Enhanced Inspection. A supplemental inspection performed that exceeds requirements of traditional detailed or visual inspections, typically a capture of infrared data.

Condition. The state of something with regard to appearance, quality, or working order that can sometimes be used to identify potential impact to normal system operation or clearance, which is typically identified by an inspection.

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.

Condition Codes. Predetermined list of codes for use by inspectors to efficiently capture 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 timeframe.

Priority Level. The level of risk assigned to the condition observed, as follows:

Imminent – imminent risk to safety or reliability

Priority A – risk of high potential impact to safety or reliability

Priority B – low or moderate risk to safety, reliability, or worker safety

2.1 STANDARD INSPECTION AND CORRECTION PROGRAMS

Pacific Power’s asset inspection program involves three primary types of inspections: (1) visual assurance inspection; (2) detailed inspection, and (3) pole test & treat. Inspection cycles, which dictate the frequency of inspections, are set by Pacific Power asset management. In general, visual assurance inspections are conducted more frequently, to quickly identify any obvious damage or defects that could affect safety or reliability. Detailed inspections have a more detailed scope of work, so they are performed less frequently than visual assurance inspections. The frequency of pole test & treat is based on the age of wood poles, and such inspections are typically scheduled in conjunction with certain detailed inspections. Regardless of the inspection type, any identified conditions are entered into a database for tracking purposes, which is Pacific Power's facility point inspection (FPI) system. For any condition identified, the inspector conducting the inspection will assign a condition code and the associated priority level. Corrections are then scheduled and completed within the correction timeframes established by Pacific Power asset management, as discussed below. While the same condition codes are used throughout Pacific Power's service territory, the timeframe for corrective action varies depending on location within the FHCA and the energy release risk. In all cases, the timeline for corrections considers the priority level of any identified condition. Under the normal correction program, conditions are corrected within the following timeframes: an A priority condition which represents an "imminent" risk to safety or reliability is corrected immediately after discovery through repair, disconnection, or isolation; an A priority level condition is addressed within 30 days; and a B priority condition, 24 months. These correction timeframes are consistent with OAR 860-024-0012. Correction timeframes are accelerated for conditions in the FHCA, as discussed in greater detail below and consistent with OAR 860-024-0018.

2.2 FHCA INSPECTION AND CORRECTION PROGRAMS

The existing inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate wildfire risk by identifying and correcting Conditions which, if uncorrected, could potentially ignite a fire. Recognizing the growing risk of wildfire and the new High Fire Risk Zone Safety Standards,[11] Pacific Power is continuing to supplement its existing programs to further mitigate the growing

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[11] OAR 860-024-0018 High Fire Risk Zone Safety Standards, effective September 22, 2022, was created through Docket No. AR 638, Rulemaking for Risk-based Wildfire Protection Plans, and formalized in Order No. 22-335.

wildfire specific operational risks and create greater resiliency against wildfires. There are three primary elements to these changes: (1) creating a fire threat classification for specific condition codes which correlate to a heightened risk of fire ignition; (2) performing inspections more often in the FHCA and (3) expediting the correction of any fire threat conditions identified within the FHCA.

Fire Threat Conditions

Pacific Power designates certain conditions as energy release risk conditions. As the name suggests, this category includes conditions which, under certain circumstances, can correlate to increase risk of a fault event and potential release of energy at the location of the condition. Certain condition codes are categorically designated as an energy release risk. If a condition is designated under a particular condition code associated as an energy release risk and the condition exists within the FHCA, the condition is designated as a fire threat condition, which means that the condition is treated as a condition type which corresponds to a heightened risk of fire ignition, as contemplated in OAR 860-024-0018(5). See figure below.

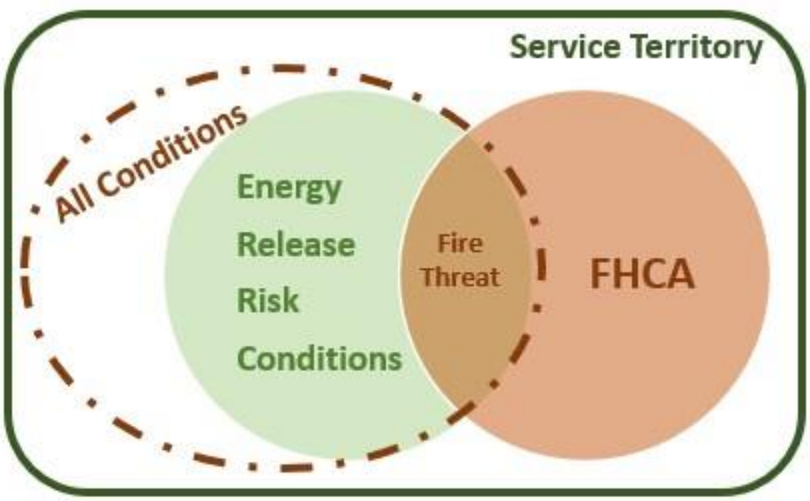


Figure 15: Fire Threat Condition Identification

To determine whether a particular condition code reflected an energy release risk, an engineering review was performed on all existing condition codes to determine whether the condition code involved equipment with an energy release risk. Condition codes reflecting an appreciable risk of energy release were designated as energy release risk conditions. For example, a damaged or frayed primary conductor has a condition code CONDFRAY, which is designated as an energy release risk condition because the condition could eventually result in a release of energy under certain circumstances. CONDFRAY conditions identified within the FHCA are then designated as a fire threat condition because, due to escalation and environmental factors, the condition could eventually result in an ignition. In contrast, the observation of a missing or broken guy marker would result in the condition code GUYMARK, which is not designated as an Energy Release Risk condition or a fire threat condition. The table below describes the general types of Energy Release Risk conditions designated by Pacific Power that, if located within the FHCA, correlate to a heightened risk of fire ignition and are then designated fire threats.

Table 5: Energy Release Risk Conditions

Condition Type	Description
POLE REPLACEMENT	A pole identified for replacement as a result of intrusive testing or visual inspection that does not meet strength requirements / safety factors
FRAYED OR DAMAGED CONDUCTOR	A conductor identified with damage/fraying on conductor strands as a result of visual or detail inspection
LOOSE CONNECTIONS / BOLTS / HARDWARE	A connection, bolt, or hardware component identified that is loose or missing from equipment or framing on the pole as a result of visual or detail inspections
LOOSE / BROKEN ANCHORS AND GUYS	Loose or broken anchor and guying identified on the pole as a result visual or detail inspections
LOOSE / DAMAGED EQUIPMENT (CAPACITORS, REGULATORS, ETC.)	Loose or damaged equipment (capacitors, regulators, reclosers, etc.) identified on the pole as a result of visual or detail inspections

Condition Type	Description
PRIMARY AND SECONDARY CONDUCTOR CLEARANCES	Primary and secondary conductor clearances from the pole, buildings, or ground that do not meet minimum clearance requirements specified in the NESC identified during visual or detail inspections
VEGETATION CLEARANCES	Vegetation clearances from the pole, primary/secondary conductor, and climbing space that do not meet minimum clearance requirements specified in the NESC identified during visual or detail inspections
LOOSE / BROKEN COMMUNICATION LASHING WIRES	One or more lashing wires (Telco, CATV, Fiber) that are broken or loose identified during visual or detail inspections
BROKEN / MISSING GROUNDS	Broken or missing ground on a pole or equipment identified during visual or detail inspections.
INFRARED	Components or equipment that has a temperature rise that exceeds thresholds in company policy identified during enhanced inspection.
UNSTABLE SOILS	Soil or backfill on a pole that is unstable or insufficient identified during visual or detail inspections.

Inspection Frequency

Pacific Power's conducts inspections on assets located within the FHCA more frequent than assets located outside of the FHCA. Consistent with industry best practices, inspections are Pacific Power's preferred mechanism to identify conditions. An increase in the frequency of inspections will result in more timely identification of potential conditions. Inspection frequencies for Oregon asset types are summarized in the following table:

Table 6: Planned Inspection Frequency in the FHCA

Inspection Type	Non-FHCA Frequency (years)	FHCA Inspection Frequency (years)
	OH Distribution and Local Transmission (Less than 200 kV)	
Visual	2	1
Detailed	10	5
Pole Test & Treat	10	10
	OH Main Grid (More than 200kV) – No Change	
Visual	1	1
Detailed	2	2
Pole Test & Treat	10	10

Expedited Correction Time Periods

Pacific Power will further mitigate wildfire risk by reducing the time for correction of fire threat conditions. As expressed above, certain types of conditions have been identified as having characteristics associated with a heightened risk of wildfire potential. Accordingly, Pacific Power is prioritizing those conditions for correction and will complete correction much sooner than allowed under the typical two-year timeframe.[12] Pacific Power performs an aggressive correction schedule where violations, recorded as Conditions, identified within the FHCA as an imminent risk to safety or reliability are required to be corrected immediately. All other fire threat conditions that correlate to a heightened risk of wildfire are required to be corrected

[12] OAR 860-024-0012 requires that "(1) A violation of the Commission Safety Rules that poses an imminent danger to life or property must be repaired, disconnected, or isolated by the operator immediately after discovery. (2) Except as otherwise provided by this rule, the operator must correct violations of Commission Safety Rules no later than two years after discovery."

within 180 days, aligned with requirements in OAR 860-024-0018(5)(b).[13] Correction timeframes for fire threat conditions are summarized in the following table:

Table 7: Planned Correction Timeframes for Fire Threat Conditions in the FHCA

Condition Priority	Correction Timeframes
Imminent fire threat conditions	Immediate
All other fire threat conditions (Energy Release Risk within the FHCA)	Up to 180 days

FHCA Inspection & Correction Programs Reasoning

In straightforward terms, Pacific Power believes that having more frequent inspections is a good mitigation strategy because more frequent inspections should, by nature, identify a certain percentage of conditions at an earlier stage than they would have otherwise been identified with less frequent inspections. If conditions are identified at an earlier date, they will, by practice and consistent with Division 24 rules, be corrected at an earlier date. And if a particular condition exists for a shorter amount of time, that particular condition is then less likely to cause a fault event or energy release, which could lead to a wildfire ignition.

When initiated in 2020, Pacific Power did not apply any particular data analytics to determine that it would be appropriate to move to a five-year cycle for detail inspections on distribution circuits and local transmission in the FHCA, versus the 10-year cycle allowed under the Division 24 rules. Pacific Power did apply general operations judgment and leveraged experience in other states to decide that halving the time between inspections was warranted

[13] OAR 860-024-0018(5)(b) requires that "Any violation which correlates to a heightened risk of fire ignition shall be corrected no later than 180 days after discovery unless an occupant receives notification under OAR 860-028-0120(6) that the violation must be corrected in less than 180 days to alleviate a significant safety risk to any operator's employees or a potential risk to the general public."

in areas of high wildfire risk. Pacific Power also notes, however, that OAR 860-024-0011(1)(b)(A) treats 10 years as a “maximum interval,” so more frequent intervals are consistent with that rule.

Since implementation of the new inspection frequencies in 2020, Pacific Power has identified more fire threat conditions per year. Accordingly, Pacific Power has corrected more fire threat conditions per year. The average differences are noted in Table 8 below.

Table 8: Average Fire Threat Conditions Identified & Corrected per Year

Average per Year	Prior to 2020	Post Changes
Fire Threat Conditions Identified	48 Conditions	131 Conditions
Fire Threat Conditions Corrected	35 Conditions	92 Conditions

Pacific Power intends to continue performing inspections more often in the FHCA to continue mitigating wildfire risk.

2.3 FOREIGN OWNED FIRE THREAT CONDITIONS

As a part of the inspection programs described above where Conditions are identified for correction by Pacific Power, the company may also identify Conditions associated with foreign owned equipment or poles that pose a potential heightened risk of wildfire. For example, a foreign owned anchor observed to be broken or loose can potentially impact the structural integrity of a pole supporting Pacific Power owned electrical equipment, posing a heightened risk of wildfire. Additionally, foreign owned lose or broken bolts and hardware necessary to secure foreign owned equipment to Pacific Power owned poles also poses a heightened risk of wildfire. As a part of the same programs described above, these conditions are collected and categorized into Energy Release Risk conditions as described in Section 3. When these Energy Release Risk conditions are located within the FHCA, these conditions are further categorized as fire threat conditions. The following table describes the subset of potential Energy Release Risk conditions that can be associated with foreign owned equipment or assets and correlate to a heightened risk of fire ignition when located within the FHCA.

Table 9: Foreign Owned Energy Release Risk Conditions

Condition Type	Description
POLE REPLACEMENT	A pole identified for replacement as a result of intrusive testing or visual inspection that does not meet strength requirements / safety factors
LOOSE / BROKEN ANCHORS AND GUYS	Loose or broken anchor and guying identified on the pole as a result of visual or detail inspections
LOOSE CONNECTIONS / BOLTS / HARDWARE	A connection, bolt, or hardware component identified that is loose or missing from equipment or framing on the pole as a result of visual or detail inspections
LASHING WIRE	Loose or broken lashing wire identified on the pole as a result of visual or detail inspections

On September 8, 2022, the OPUC adopted new requirements under rule OAR 860-024-0018 – High Fire Risk Zone Safety Standards which will provide Operators of electric facilities new processes and require correction or escalation of conditions associated with foreign owned assets that pose a heightened risk of fire ignition in High Fire Risk Zones. Pacific Power plans on utilizing these new processes to ether correct, request correction of, or escalate unresolved correction of these fire threat conditions associated with foreign owned equipment and assets in FHCA areas in Oregon.

Notification. The notification process required under 860-024-0018 is similar to processes currently used by Pacific Power in that it involves consuming data from two internal planning tools, segregating the list of conditions that correlate to an energy release risk, and were found in FHCA areas. For such conditions on Pacific Power owned poles, notifications are communicated to attaching entities based upon Pacific Power attachment records. For such conditions on foreign owned poles, notifications are communicated to the foreign pole owners based upon Pacific Power's pole ownership records. These notifications, which are made in accordance with the timeframes required under OAR 860-024-0018(6) leverage customer letter templates and include a description of the condition in question, location information, correction timeframes required under the OAR, and next steps available to Pacific Power under the OAR in the event the notified party does not take action to correct the conditions.

Correction. Consistent with OAR 860-024-0018 and the correction of electric utility related fire threat conditions, the following describes the required timelines associated with correction of foreign owned asset related fire threat conditions.

Table 10: Fire Threat Condition Correction Timeframes for Foreign Owned Equipment & Assets

Condition Priority	Correction Timeframes
Imminent fire threat conditions	Immediate
All other fire threat conditions (Energy Release Risk within the FHCA)	Up to 180 days

Pacific Power plans to require correction of fire threats associated with foreign owned equipment and assets consistent with these timeframes. Where the equipment or asset owner is unresponsive, Pacific Power may correct some fire threat conditions on behalf of the owner to mitigate wildfire risk and charge the pole owner or equipment owner a replacement fee of 25% of the total amount of work.[14]

Escalation. If Pacific Power does not make the repair and the notified party has not fulfilled its obligations to correct the condition, Pacific Power will assemble the necessary documentation required for filing a complaint under 860-024-0061, fill out the requisite form

[14] See OAR 860-024-0018(6) which states "If the pole owner or equipment owner does not replace the reject pole or repair the equipment within the timeframe set forth in the notice, then the Operator of electric facilities may repair the equipment or replace the pole and seek reimbursement of all work related to correction or replacement of the reject pole or equipment including, but not limited to, administrative and labor costs related to the inspection, permitting, and replacement of the reject pole. The Operator of electric facilities is also authorized to charge the pole owner or equipment owner a replacement fee of 25 percent of the total amount of work."

and file the complaint with the commission. If Pacific Power performs the correction of the condition after first providing the notified party the requisite opportunity to correct the condition, Pacific Power will invoice the notified party in accordance with the OAR. If the invoiced party does not pay the invoice, Pacific Power may file a complaint with the commission in accordance with the OAR, to compel payment.

2.4 ENHANCED INSPECTIONS

Pacific Power's enhanced inspection utilizes alternate technologies to identify hot spots, equipment degradation, and potentially substandard connections that aren't detectable through a visual inspection. Infrared data is gathered using a helicopter flying over the designated lines within Pacific Power's service territory near peak loading intervals and is performed incrementally to existing inspection programs. Hot spots on power lines identified through infrared data gathering can be indicative of loose connections, deterioration and/or potential future energy release locations. Therefore, identification and removal of hot spots on overhead transmission lines can reduce the potential for equipment failure and faults and mitigate the risk of ignition.

Identified Lines. Beginning in 2021 and described in Pacific Power's 2022 Oregon WMP, the company performs enhanced inspections annually on overhead transmission lines operating at 69kV, 115kV, 230kV, or 500kV with at least a single structure residing in the FHCA. This scope includes areas in Southern Oregon, Hood River, and Enterprise totaling 35 line-segments and approximately 1,000 line-miles. Based on successes experienced in Oregon as well as multiple years of experience in other states, Pacific Power plans to expand the scope to all overhead transmission lines throughout Oregon which includes an additional 2,000 line-miles on 116 line-segments. A map illustrating the transmission lines that are currently inspected and planned for enhanced inspections is provided below.

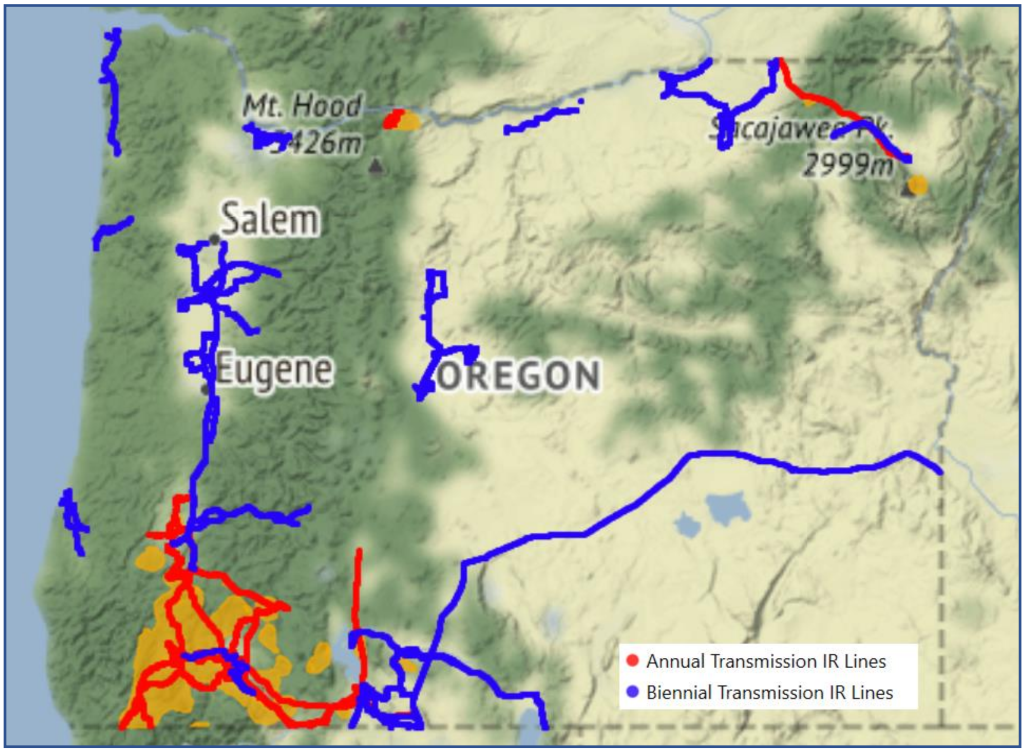


Figure 16: Map of Enhanced Transmission Line Inspections

Inspection Frequency. Pacific Power varies inspection frequency between circuits in the FHCA and non-FHCA areas as described above in Section 3 Using a similar approach, Pacific Power is also planning to vary enhanced inspection frequency between circuits in FHCA and non-FHCA areas beginning in 2023. As described in Section 1.1, assets located within FHCA areas are considered to have a heightened risk of wildfire. Therefore, Pacific Power performs enhanced inspections on overhead transmission lines within the FHCA annually. If a transmission line has a single structure contained within the FHCA; the entirety of the line is inspected. In addition to lines within the FHCA, Pacific Power plans to begin performing enhanced inspections on lines outside of the FHCA areas on a biennial basis. As described previously, these frequency intervals were determined based on successes that have been experienced in Oregon as well as multiple years of experience in other states. Enhanced inspection frequencies are summarized in the following table:

Table 11: Summary of Enhanced Inspection Frequency on Transmission Lines

	Frequency	Line Miles
FHCA	Annually	1,000
Non-FHCA	Biennially	2,000

Inspection Intervals/Bundling. Different than patrol or detailed inspections, enhanced inspections are performed annually by a trained thermographer assisted by a qualified transmission line patrolman, where lines are "bundled" depending on peak loading events. Peak loading events are seasonal with three main intervals; winter months DEC-FEB (7am and 11am), the spring months APR-JUN (anytime) as the hydro sites have the winter runoff, and the summer months JUL-AUG (3pm-8pm). Inspecting during peak loading ensures the highest probability of detecting abnormal thermal rises on the equipment induced by system loading.

Corrective Action. Similar to other inspection and correction programs, Pacific Power takes a tiered approach to correcting any anomalies identified during an enhanced inspection. Findings are separated into three severity ranges depending on the measured temperature rise over anticipated conditions and general assessment and recommendation from the trained thermographer. These recommended time periods for correction align with the accelerated correction time periods of other conditions identified in the FHCA and are scheduled per policy.

Enhanced Inspection & Correction Reasoning

Similar to the FHCA Inspection and Correction Program, Pacific Power believes that having more frequent enhanced inspections is a good mitigation strategy. Increased inspections should identify a certain percentage of conditions at an earlier stage than they would have otherwise been identified with a less frequent interval. As described above, enhanced inspections utilize alternate technologies to identify hot spots, equipment degradation, and potentially substandard connections that aren't detectable through a visual inspection. Therefore, Pacific Power believes that more frequent enhanced inspections reduce wildfire risk incrementally to the FHCA and standard inspection programs.

When performed in 2022, Pacific Power did not apply any particular data analytics to determine that it would be appropriate to perform an annual enhanced inspection on OH transmission lines in the FHCA. Pacific Power did apply general operations judgment and leveraged experience in other states to decide that an annual enhanced inspection was warranted in areas with high wildfire risk. Additionally, Pacific Power has observed new conditions during each year of its program, indicating that an annual enhanced inspection can incrementally mitigate risk.

Since implementation of the new inspection frequencies in 2021, Pacific Power has identified 16 incremental conditions for correction in Oregon and 36 in other states not identified through the other inspection programs. Generally, conditions identified for correction were on splices and jumper connections. Specific results in each year can vary due to the assets being inspected, environmental factors during data collection, and maturation of the program, each incremental condition identified and corrected represents an incremental reduction in risk.

Table 12: Incremental Conditions Identified & Corrected through Enhanced Inspections

Total Incremental Conditions	Incremental Conditions	Conditions Found per Mile Inspected
Conditions Identified in OR	16 Conditions	1/135
Conditions Identified throughout All States	36 Conditions	1/170

Pacific Power intends to continue performing enhanced inspections more often in the FHCA to continue mitigating wildfire risk.

3. Vegetation Management

Vegetation management is generally recognized as a significant strategy in any WMP. Vegetation contacting a power line is a potential source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it is impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of Pacific Power's existing vegetation management program is to minimize contact between vegetation and power lines by addressing grow-in and fall-in risks. This objective is in alignment with core WMP efforts, and continuing dedication to administering existing programs is a solid foundation for Pacific Power's WMP efforts. To supplement the existing program, Pacific Power vegetation management is implementing additional WMP strategies in FHCA.

3.1 REGULAR VEGETATION MANAGEMENT PROGRAM

The focus of Pacific Power's vegetation management efforts is to minimize safety, reliability, and wildfire ignition risks. Pacific Power prunes tall growing vegetation to maintain a safe distance between vegetation and power lines. Pacific Power also removes vegetation, such as dead, dying, diseased or otherwise impacted trees, that pose an elevated risk of falling into a power line. Similar to other utilities, Pacific Power contracts with vegetation management service providers to perform the pruning and tree removal work for both transmission and distribution lines.[15]

Distribution

Vegetation management activities on distribution circuits in Oregon are generally performed on a planned cycle where vegetation along a circuit scheduled for cycle maintenance is inspected and vegetation requiring work is identified for pruning or removal. Vegetation is

[15] Pacific Power's vegetation management program is described in detail in Pacific Power's Transmission & Distribution Vegetation Management Program Standard Operating Procedures, which guides the work done by vegetation contractors.

pruned to achieve minimum post work clearance distances to help maintain conductor to vegetation clearance. Because some trees grow faster than others, minimum post-work clearance distances vary depending on the type of tree being pruned. For example, faster growing trees need a greater minimum post-work clearance to maintain required clearance throughout the cycle.

Pacific Power also integrates spatial concepts to distinguish between side clearances, under clearances, and overhang clearances. Recognizing that certain trees grow vertically faster than other trees, it is appropriate to use an increased clearance when moderate or fast-growing trees are under a conductor.

The minimum post-work clearance distances are designed to maintain regulatory mandated clearance with primary lines. Pacific Power is effectively increasing minimum post-work clearances in all areas, because contractors will continue to prune to the clearance distances previously used with the four-year cycle when doing work under the new three-year cycle. This approach should further enhance maintenance of clearances at all times. The specific distances for the minimum post-work clearance distances in non-FHCA identified by Pacific Power are as follows:

Table 13: OR Distribution Minimum Post-Work Vegetation Clearance Distances, Non-FHCA

	SLOW GROWING (<1 FT/YR.)	MODERATE GROWING (1-3 FT/YR.)	FAST GROWING (> 3 FT./YR.)
SIDE CLEARANCE	8 ft.	10 ft.	14 ft.
UNDER CLEARANCE	10 ft.	14 ft.	16 ft.
OVERHANG CLEARANCE	12 ft.	14 ft.	14 ft.

Post-work clearance distances within FHCA are as follows

Table 14: OR Distribution Minimum Post-Work Vegetation Clearance Distances, FHCA

	SLOW GROWING (<1 FT/YR.)	MODERATE GROWING (1-3 FT/YR.)	FAST GROWING (> 3 FT./YR.)
SIDE CLEARANCE	12 ft.	12 ft.	14 ft.
UNDER CLEARANCE	12 ft.	14 ft.	16 ft.
OVERHANG CLEARANCE	12 ft.	14 ft.	14 ft.

When a tree is pruned, natural target pruning techniques are used to minimize injury to the tree and allow the tree to efficiently heal. Natural targets are the final pruning cut location at a strong point in a tree's disease defense system, which are branch collars and proper laterals. Pruning at natural targets protects the joining trunk or limb.[16] Consequently, an actual cut is typically beyond the minimum post-work clearance distance listed in the tables above. In all cases, however, the cut is at least to the minimum post-work clearance distance unless extenuating circumstances prevent full post-work clearance.

Pacific Power also removes high-risk trees as part of distribution cycle work, to minimize vegetation contact through fall-in risk. High-risk trees are defined in Pacific Power's Transmission and Distribution Vegetation Management Program Standard Operating Procedures (SOP) as "dead, dying, diseased, deformed, or unstable trees that have a high probability of falling and contacting a substation, distribution conductor, transmission conductor, structure, guys or other [Pacific Power] electric facility."[17] Inspections are performed on distribution lines in advance of distribution cycle maintenance work, to identify which trees will be worked in the cycle, including high-risk trees subject to removal. To identify high risk trees, Pacific Power uses best management practices,[18] including an initial Level 1 assessment, taking into consideration factors such as prevailing winds and slope. The inspector may conduct a closer inspection or Level 2 assessment of suspect trees, to further

[16] This technique is drawn from ISA Best Management Practices: Tree Pruning (Gilman and Lilly 2002) and A300 (ANSI 2008). (See also Miller, Randall H., 1998. Why Utilities "V-Out" Trees. Arborist News. 7(2):9-16.)

[17] See Table 2 of FAC-003-04, at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

[18] ANSI A300 (Part 9); Smiley, Matheny and Lilly (2011), Best Management Practices: Tree Risk Assessment, International Society of Arboriculture

assess their condition. After the work is completed, Pacific Power conducts post-work inspections as part of an audit and quality review process.

Distribution cycle work also includes work designed to reduce future work volumes. In particular, volunteer saplings, small trees that were not intentionally planted, are typically removed if they could eventually grow into a power line. From a long-term perspective, this type of inventory reduction helps mitigate wildfire risk by eliminating a potential vegetation contact long before it could ever occur.

Vegetation management on distribution circuits in Oregon has historically been completed on a four-year cycle (with interim work performed where warranted, halfway through the cycle). In 2022, Pacific Power adopted a three-year cycle for all vegetation management work in Oregon. Through this transition Pacific Power is completing additional vegetation management inspection and correction activities on circuits that are considered to be “off-schedule“ (i.e., circuits that were scheduled for work on the four-year cycle now fall within a later calendar year within the three-year cycle). This additional work related to the cycle transition is expected to continue through 2023 at a minimum. As a result, incremental WMP related costs associated with the transition to a three-year cycle are included throughout 2023 but are anticipated to decrease slightly after 2023.

Transmission

Vegetation management on transmission lines is also focused on maintaining clearances, however, the clearance distances are greater. Because of the nature of transmission lines, wider rights-of-way generally allow Pacific Power to maintain clearances well in excess of the required minimum clearances set forth in the “Minimum Vegetation Clearance Distance” (MVCD[19]). Accordingly, rather than scheduling vegetation management work for transmission

[19] See Table 2 of FAC-003-04, at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

lines on a fixed cycle timeframe, such work is scheduled on an as-needed basis, depending on the results of regular inspections and specific local conditions. To determine whether work is needed, an "Action Threshold" is applied, meaning that work is done if vegetation has grown within the action threshold distance. When work is completed, vegetation is cleared to the minimum post-work clearance as specified in the table below:

Table 15: Transmission Minimum Vegetation Clearance (in Feet) by Line Voltage

	500 KV	345 KV	230 KV	161 KV	138 KV	115 KV	69 KV	45 KV
MINIMUM VEGETATION CLEARANCE DISTANCE (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	5
MINIMUM CLEARANCES FOLLOWING WORK	50	40	30	30	30	30	25	20

In some circumstances, when local conditions and property rights allow, Pacific Power may use "Integrated Vegetation Management" (IVM) practices to prevent vegetation growth from violating clearances. Rather than depending on pruning in regular work cycles, IVM seeks to prevent clearance issues from emerging, by proactively managing the species of trees and other vegetation growing in the right-of-way. Under such an approach, Pacific Power may remove tree species that could potentially threaten clearance requirements, while encouraging low-growing cover vegetation, which would never implicate clearance issues.

Line Patrol Workers inspect most transmission lines annually and notify the vegetation management department of any vegetation conditions. Pacific Power's utility Forestry Arborists (foresters) and/or contracted vegetation management forest technicians also conduct regular inspections of vegetation near transmission lines, including annual inspections of vegetation on all main grid transmission lines. Vegetation work is scheduled dependent on a number of local factors, consistent with industry standards and best management practices. Vegetation work on local transmission overbuild is completed on the distribution cycle schedule and inspected accordingly.

3.2 FHCA VEGETATION MANAGEMENT

In addition to normal vegetation maintenance work discussed above, Pacific Power's vegetation management specifically targets risk reduction in the FHCA with three distinct strategies. First, Pacific Power vegetation management conducts annual vegetation inspections on all lines in the FHCA, with correction work also completed based on inspection results. Second, Pacific Power uses increased minimum clearance distances for distribution cycle work completed in the FHCA. Third, Pacific Power is implementing annual pole clearing on subject equipment poles located in the FHCA. To accomplish these new WMP strategies, Pacific Power anticipates adding internal resources and currently plans to recruit approximately 3 additional FTEs.

Annual FHCA Vegetation Inspection

Pacific Power vegetation management performs an annual vegetation inspection for all lines, or portions of lines located, in the FHCA This tool is an effective strategy to identify high-risk trees. This strategy facilitates removal of high-risk trees before such trees could ever fall into a line and cause a wildfire. The annual inspection includes both on-cycle and off-cycle work to achieve an annual inspection of all line miles within FHCA.

Extended Clearances

Pacific Power uses increased minimum post-work clearance specifications distances for any distribution cycle work in the FHCA. These minimum post-work clearance distances require pruning to at least 12 feet, in all directions and for all types of trees, when work is identified as needed. As discussed above, minimum clearance specification distances identify the distance achieved after pruning is completed. By increasing the minimum distance required at the time pruning is done, Pacific Power further minimizes the potential of vegetation contacting a power line at any time. The planned minimum clearance distances for the FHCA are as follows:

Table 16: Distribution Minimum Vegetation Clearance Specifications in the FHCA

	SLOW GROWING (<1 FT./YR.)	MODERATE GROWING (1-3 FT./YR.)	FAST GROWING (>3FT./YR.)
SIDE CLEARANCE	12 ft.	12 ft.	14 ft.
UNDER CLEARANCE	12 ft.	14 ft.	16 ft.
OVERHANG CLEARANCE	12 ft.	14 ft.	14 ft.

While certain fast-growing trees can sometimes exceed expected annual growth, these minimum post-work clearance specifications are designed with the expectation that such clearances achieved at the time of work will minimize the potential for vegetation impinging required minimum clearance distances at any time before the next work cycle.

Pole Clearing

Pacific Power vegetation management performs pole clearing on subject equipment poles located in the FHCA. Pole clearing involves removing all vegetation within a 10-foot radius cylinder (up to 8 feet vertically) of clear space around a subject pole and applying herbicides and/or soil sterilant to prevent any vegetation regrowth (unless prohibited by law or the property owner). See below.

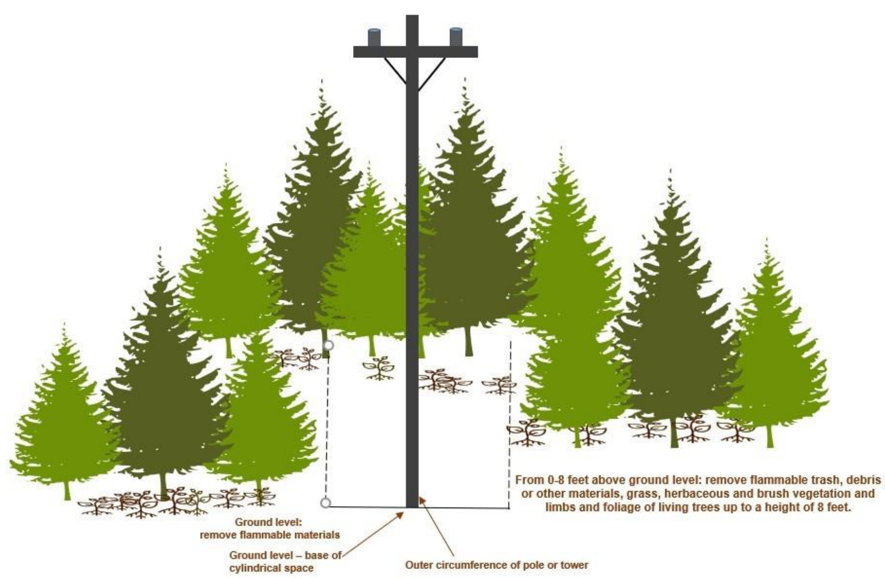


Figure 17: Pole Clearing Strategy

This strategy is distinct from the clearance and removal activities discussed above because it is not designed to prevent contact between vegetation and a power line. Instead, pole clearing is designed to reduce the risk of fire ignition if sparks are emitted from electrical equipment. Pole clearing will be performed on wildland vegetation in the FHCA around poles that have fuses, air switches, clamps or other devices that could create sparks. After a pole has been cleared, a spark falling within the 10-foot radius would be much less likely to ignite a fire.

Continuous Improvement Plans

Pacific Power vegetation management will continue to evaluate other strategies and emerging industry standards and best practices in the arena of wildfire mitigation. Along these lines, Pacific Power may implement additional vegetation management strategies in a subsequent WMP as strategies and best management practices evolve considering wildfire ignition risk.

3.3 POST WORK AUDITS

After work is completed by Pacific Power's vegetation management contractors, Pacific Power conducts post-audits (quality control reviews) to compare completed work against specifications, such as post-work clearances. Post-audits are completed annually and include review of routine maintenance and additional work completed annually within the FHCA. Post-audits are primarily conducted by Pacific Power internal ISA certified staff. ISA certified contract staff may assist on a as needed basis. As identified in Section 3.2, Pacific Power is hiring additional staff throughout its service territory to increase internal post-audit capacity. Post-audits are generally conducted soon after the vegetation management work is completed at a location, to identify any issues before vegetation management crews leave the area for their next work assignment. Post-audits are intended to identify recurring quality-related issues early on, so that Pacific Power staff can review with the contractors conducting the work and implement any needed corrective measures.

The staff conducting post-audits record work exceptions (inconsistencies with Pacific Power specifications or work missed) using its mobile data management software. The audit exceptions are then visible to the vegetation management contractor within the mobile data management software and assigned to that contractor, who remains responsible for the work, including any corrective action.

4. System Hardening

Pacific Power's electrical infrastructure is engineered, designed, and operated in a manner consistent with prudent utility practice, enabling the delivery of safe, reliable power to all customers. When installing new assets, Pacific Power is committed to incorporating the latest technology and engineered solutions. When conditions warrant, Pacific Power may engage in strategic system hardening, which may consist of replacing existing assets (or, in some circumstances, modifying existing assets using a new design and additional equipment) to make the assets more resilient. Recognizing the growing risk of wildfire, Pacific Power plans to supplement existing asset replacement projects with system hardening programs designed to mitigate specific operational risks associated with wildfire.

System hardening programs are designed in reference to the equipment on the electrical network that could be involved in the ignition of a wildfire or be subject to an existing wildfire event. In general, system hardening programs attempt to reduce the occurrence of events involving the emission of sparks (or other forms of heat) from electrical facilities or reduce the impact of an existing wildfire on utility infrastructure. System hardening programs represent the greatest long-term mitigation tool available for use by electric utilities. The phasing and prioritization of such programs is therefore focused on locations that present the greatest risk.

No single system hardening program mitigates all wildfire risk related to all types of equipment. Individual programs address different factors, different circumstances, and different geographic areas. Each program described below, however, shares the common objective of reducing overall wildfire risk associated with the design and type of equipment used to construct electrical facilities. In prioritizing particular design or equipment elements, these programs can also consider environmental factors impacting the magnitude of a wildfire. Dry and windy conditions pose the greatest degree of risk. Consequently, system hardening programs may specifically attempt to reduce the potential of an ignition event when it is dry and windy, by looking at equipment that is more susceptible to failure or contact with foreign objects when it is dry and windy.

It must be emphasized, however, that system hardening cannot prevent all ignitions, no matter how much is invested in the electrical network. Equipment does not always work perfectly and, even when manufactured and maintained properly, can age, and fail; in addition, there are external forces and factors impacting equipment, including from third parties and natural conditions. Therefore, Pacific Power cannot guarantee that a spark or heat coming from equipment owned and operated by Pacific Power will never ignite a wildfire. Instead, Pacific Power seeks to reduce the potential of an ignition associated with any electrical equipment. To this end, Pacific Power plans to make investments with targeted system hardening programs.

Pacific Power developed new design standards applicable to new construction in areas of elevated wildfire risk, described in the construction standards section. The idea of "system hardening" applies in these contexts, as Pacific Power plans for new construction to be "hardened" against wildfire risk. However, system hardening referenced in this plan is geared toward specific programs aimed at making existing facilities more resistant to wildfire, even though those existing facilities are fully functional and do not require any corrective work under current utility practices.

Pacific Power has learned several ways to streamline the process of completing system hardening projects as progress is made. Line rebuild projects are being segmented efficiently based off of permitting requirements. Segments that requiring simple permits are prioritized and can move into construction while the permits for the more involved segments are sought and planned for. Additionally, Pacific Power has been working with the Klamath National Forest (KNF) to develop a maintenance agreement for work on KNF managed lands to streamline the permitting process. As for the expulsion fuse replacement project, replacements on transformers have been added into Pacific Power's ArcGIS driven Field Maps program allowing line workers to identify in-scope work that remains, complete the work, and report a completion using an application.

4.1 LINE REBUILD PROGRAM

Pacific Power has evaluated specific areas for system hardening work. The wildfire risk assessment and, more specifically, the identified risk zones identified for hardening discussed in Section 1, is an important factor in evaluating where work is appropriate. Pacific Power has identified areas in Oregon where bare overhead wire may be replaced with covered conductor.

Where appropriate, poles will either be replaced with fiberglass or made more fire resilient (by fire protective treatment methods). Additionally, where conductor diameters do not support fault current properly (due to the limited arc energy they can tolerate), they will be replaced, generally with covered conductor. After being rebuilt, such lines will be more tolerant to incidental contact, while also able to tolerate greater levels of fault event arc energy.

The company used different criteria to determine which lines are included within the line rebuild program. First, because of the heightened risk in the FHCA, all lines included in the rebuild program are located at least partially in the FHCA and typically included in a risk zone identified for hardening. Certain segments of a rebuild might extend outside the FHCA, based on the location of substations or protective devices. In general, however, the vast majority of rebuild work is in the FHCA and associated with specific risk zones identified for hardening.

Covered Conductor. Historically, the vast majority of high voltage power lines in the United States – and in Pacific Power's service territory – were installed with bare overhead conductor. As the name "bare" suggests, the wire surface is uninsulated and exposed to the elements.

Figure 18: Lineworkers Preparing a Pole for New Covered Conductor

For purposes of wildfire mitigation, a new conductor design has emerged as an industry best practice. Most of the projects in the Line Rebuild Program will involve the installation of insulated covered conductor. Sometimes, with some variations in products, covered conductor is also called spacer cable, aerial cable, or tree wire.

The dominant characteristic of covered conductor is manufactured with multiple high-impact resistant extruded layers forming an insulation around stranded hard drawn conductor. As a comparison, covered conductor is like an extension power cord that you might use in your garage. The inherent design provides insulation for the energized metal conductor. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). But the principle is the same. The insulating layers have proven to effectively reduce the risk of wildfire by minimizing the vegetation or ground contact over bare conductor.

Variations in covered conductor products have been used in the industry for decades. Due to many operating constraints, however, use of covered conductor tended to be limited to locations with extremely dense vegetation where traditional vegetation management was not feasible or efficient. Recent technological developments have remarkably improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the project and reduced the impact of conductor thermal constraints (i.e., bare conductor has higher thermal constraints over covered conductor). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially during heavy snow/ice loading, meaning that more and/or stronger poles may be required to support covered conductor. And the product itself is more expensive than bare conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment section, a disruption on the electrical network, a fault, can result in emission of spark or heat that could be a potential source of ignition. Covered conductor greatly reduces the potential of many kinds of faults. For example, contact from object is major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line and pushing two phases together or a Mylar balloon carried by the wind drifting into a line, contact with energized bare conductor can cause the emission of sparks. If those same objects contact covered conductor, the wire is insulated enough that there are no sparks. Likewise, many equipment failures are a wildfire risk because the equipment failure then allows a bare conductor to contact a grounded object. Consequently, covered conductor greatly reduces the risk of ignition associated with most types of equipment failure. For example, if a cross arm breaks, the wire held up by the cross arm often falls to the ground (or low and out of position, so that the wire might be contacting vegetation on the ground or the pole itself). In those circumstances, a bare conductor can emit sparks (or heat) that can cause an ignition. The use of covered conductor, in those exact same circumstances, would almost certainly not lead to an ignition, because the insulation around the wire is sufficient enough to prevent any sparks and limit energy flow, even when there is contact with an object.

Covered conductor is especially well-suited to reduce the occurrence of faults linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind, in particular, is the driving force behind wildfire spread. At the same time, wind has distinct and negative impacts on a power line. The wind blows objects into lines; a strong wind can cause equipment failure; and even parallel lines slapping in the wind can cause sparks. Covered conductor specifically reduces the potential of a ignition event, because covered conductor is especially effective at limiting the kinds of faults that occur when it is windy. Taken together, these substantial benefits warrant the use of covered conductor in areas with a high wildfire risk. This approach is consistent with emerging best practices, as utilities in geographic areas with extreme wildfire risk have trended heavily towards use of covered conductor.

Underground. Pacific Power also continues to evaluate the potential to convert overhead lines to underground lines for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not completely eliminate every ignition potential (i.e., because of above-ground junctions), it is the most effective design to most dramatically reduce the risk of any utility-related ignition. Currently, the cost and operational constraints of underground construction often make it difficult to apply on a widespread basis. Nonetheless, some electric utilities are planning to employ an underground strategy more broadly.

At this time, Pacific Power is evaluating the use of underground design as part of the rebuild program on a project-by-project basis; and it will use under-grounding where practical. Through the design process, each individual rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. For example, a section of a seven (7) mile rebuild project near Hood River that crosses a railroad and I-84 is currently being designed and permitted as underground with construction to follow in 2024. Additionally, some communities and landowners may also prefer to pursue a higher cost underground alternative for aesthetic reasons, and Pacific Power will continue to work with communities or individual landowners willing to pay incremental costs.

Non-Wooden Poles. Traditionally, overhead poles are replaced or reinforced within Pacific Power’s service territory consistent with state specific requirements and prudent utility practice. When a pole is identified for replacement, typically through routine inspections and testing, major weather events, or joint use accommodation projects, a new pole consistent with engineering specifications suitable for the intended use and design is installed in its place. Engineering specifications typically reflect the use of wooden poles which is consistent with prudent utility practice and considered safe and structurally sufficient to support overhead electrical facilities during standard operating conditions. However, the use of alternate non-wooden construction, such as steel or fiberglass, can provide additional structural resilience in high-risk locations during wildfire events and, therefore, aid in restoration efforts.

In addition to the installation of non-wooden solutions as a part of standard replacement programs or mechanisms in priority locations with increased risk, certain wooden poles may also be replaced with non-wooden solutions in conjunction with other wildfire mitigation system hardening programs. For example, as a part of covered conductor installation, the strength of existing poles is evaluated. In many cases, the strength of existing poles may not be sufficient to accommodate the additional weight of covered conductor. In these instances, the existing wooden pole is upgraded to support the increased strength requirements and, when present in high priority locations, replaced with a non-wooden solution for added resilience.

Line Rebuild Summary

In 2022, Pacific Power successfully constructed 2 miles of covered conductor and engineered approximately 91 miles of covered conductor for construction in 2023. Unlike many distribution construction projects, the use of covered conductor often requires a custom engineered design for each project, long lead unique materials, specialized resources, and a larger volume of personnel to construct. In addition, permitting can incrementally increase project timelines significantly. As a result, project timelines are usually longer than bare conductor projects, often requiring over a year for scoping and design phases and another year for material delivery, permitting, and deployment. Pacific Power is in the early stages of ramping up this effort and plans to look for opportunities for acceleration where possible. For example, in 2022, Pacific Power began leasing additional material storage space in southern

Oregon to support expediting delivery of projects. Pacific Power plans to continue leasing this facility in support of the line rebuild program in 2023.

As a part of the on-going program, Pacific Power is currently forecasting to rebuild approximately 591 miles of overhead line over the next 5 years depending on project pipeline and delivery constraints. To date, Pacific Power has identified and completed detailed scoping of approximately 89 miles to be rebuilt by year end 2023 to mitigate risk on five (5) circuits in Grants Pass. These projects were selected consistent with the initial baseline risk analysis discussed in Section 1.1 to initiate the program and begin moving projects through the pipeline. These specific projects are depicted in the image below.

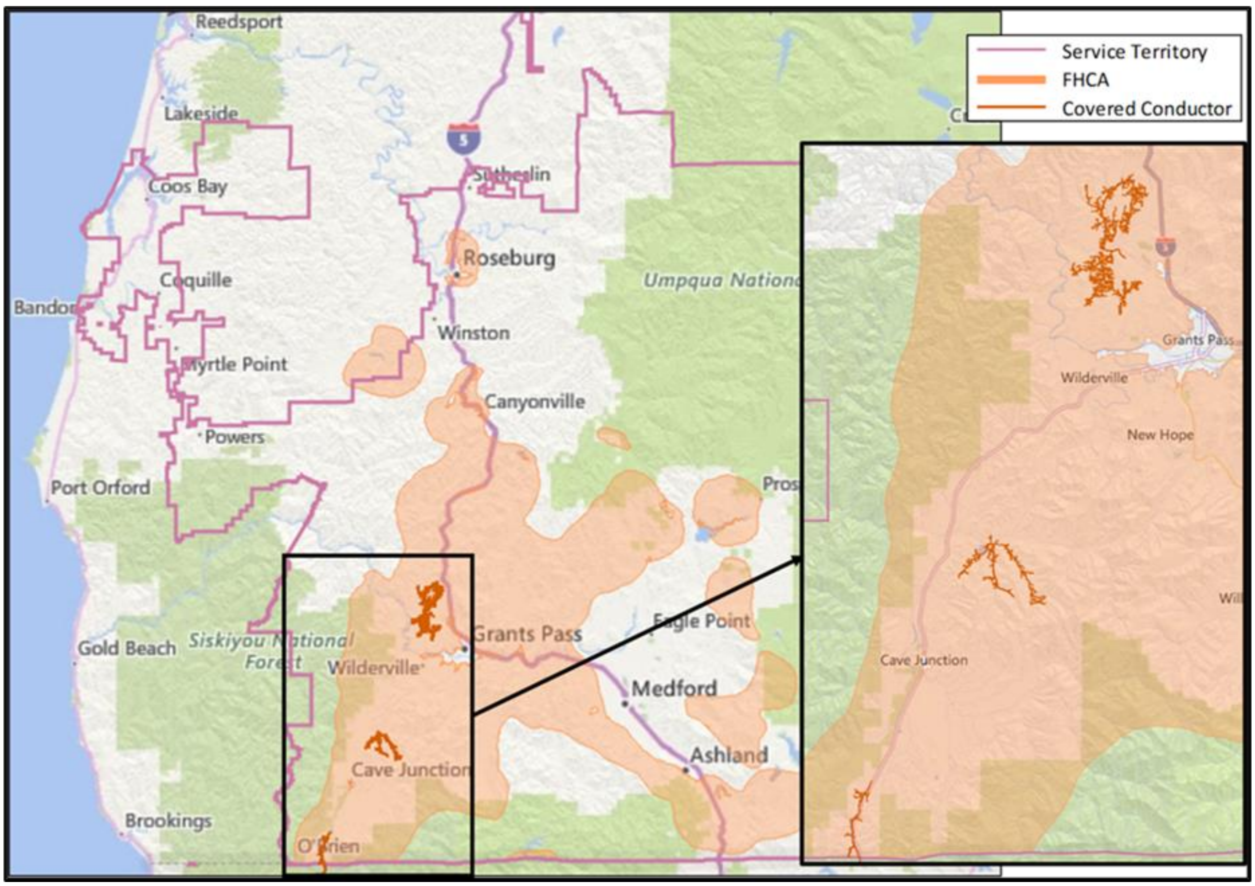


Figure 19: 2022 Completed & 2023 Planned Construction Projects

To provide repeatability, sustainability, and enhanced transparency in project selection, prioritization, and decision making. Pacific Power is investing in new datasets, software, and tools described in Section 1.4. Once implemented, these tools will significantly impact on the line rebuild program and future project selection and scoping. Pacific Power intends to leverage these new tools beginning in 2023 to inform construction of projects beginning in 2024. The overall program construction forecasted is included in the table below.

Table 17: Line Rebuild Program Forecast

PROJECT COMPONENT	2022 ACTUALS	2023	2024	2025	2026	2027	TOTAL[20]
Scoping & Design (miles)	91	125	125	125	125	125	716
Construction (miles)	2	89	125	125	125	125	591

The 591 miles currently forecasted in this five-year plan only represent 3.7% of Pacific Power's overhead lines throughout Oregon. As Pacific Power learns more about risk and the longer-term effects of climate change in the region, the company anticipates that this program could expand beyond this initial forecast. Pacific Power is investing in new project selection and prioritization tools and software to characterize and identify risk and mitigation projects and is prepared to implement additional, necessary measures to mitigate risk.

4.2 ADVANCED SYSTEM PROTECTION AND CONTROL

Pacific Power is continuing to replace and upgrade electro-mechanical relays with microprocessor relays throughout the FHCA. Microprocessor relays provide multiple wildfire mitigation benefits. They are able to exercise programmed functions much faster than an electro-mechanical relay and above all, the faster relay limits the length and magnitude of fault events. After a fault occurs, energy is released, posing a risk of ignition, until the fault is cleared. Reducing the duration of a fault event reduces the risk that the fault might result in a fire.

[20] The current forecast includes rebuilding approximately 585 miles over 5 years (2023-2027). Pacific Power anticipated the line rebuild program will continue beyond 2027. Additionally, where practical Pacific Power will look to accelerate construction activities.

Additionally, microprocessor relays also allow for greater customization to address environmental conditions through a variety of settings and are better able to incorporate complex logic to execute specific operations. These functional features allow for the company to use more refined settings for application during periods of greater wildfire risk, which will be discussed in Section 6.

Finally, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis. In certain circumstances, this information can help the company locate and correct a condition prior to the condition leading to a more serious event. At a minimum, such information facilitates better knowledge of the network, possibly shaping future mitigation strategies. As part of replacing an electro-mechanical relay, the associated circuit breaker or other line equipment may also be replaced, as appropriate to facilitate the functionality of a microprocessor relay.

Pacific Power plans to replace 138 relays and 151 reclosers over approximately 5 years, with completion planned in 2026. Pacific Power anticipates that this program could expand as the company learns more about risk and advances its risk modeling capabilities described in Section 1.4. In 2022, Pacific Power upgraded a total of 62 devices as a part of this program. See image and table below for existing program scope and overall progress.

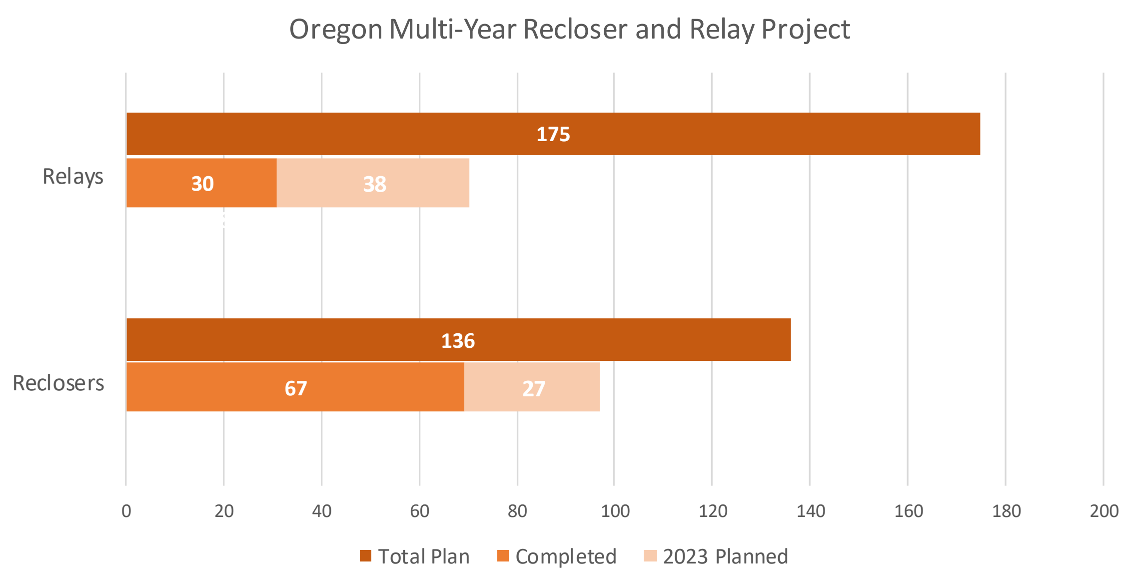


Figure 20: System Automation Project Progress

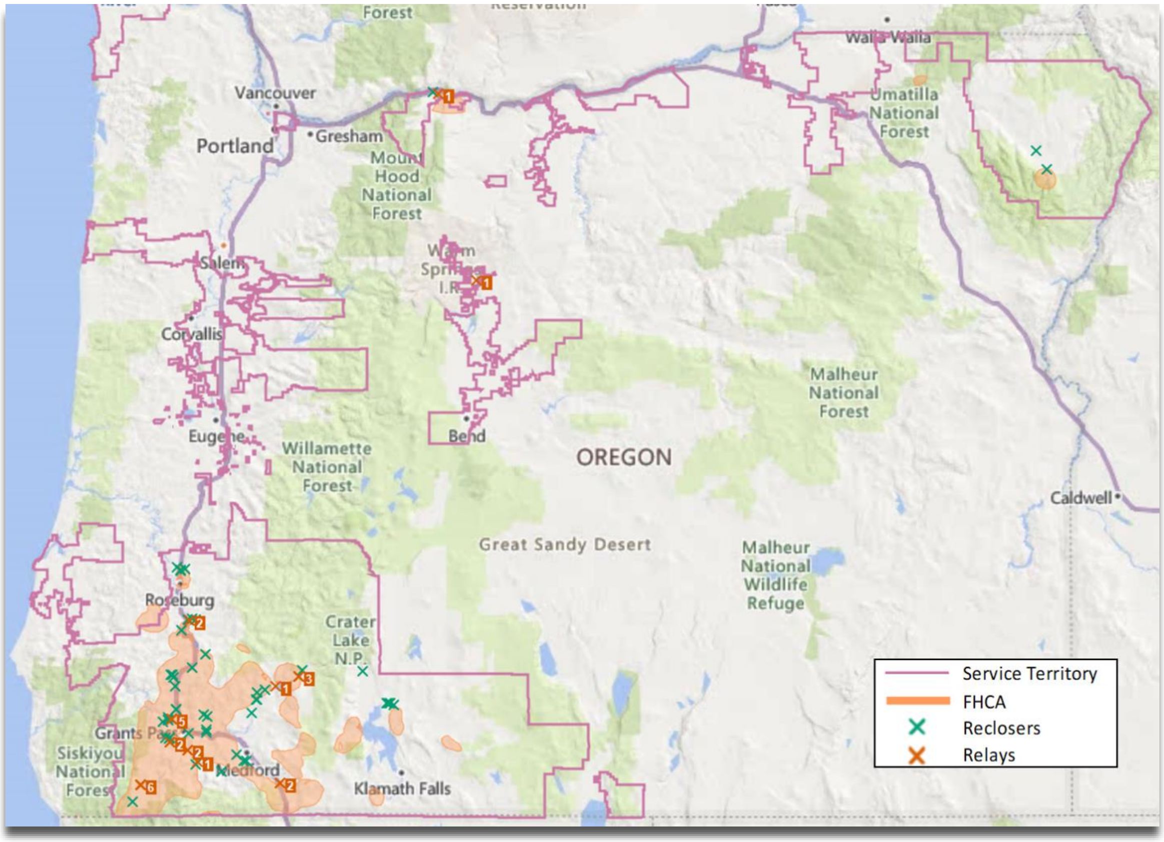


Figure 21: Oregon 2022 Completed Reclosers and Relays Map

4.3 EXPULSION FUSE REPLACEMENT

Overhead expulsion fuses serve as one of the primary system protection devices on the overhead system. The expulsion fuse has a small metal element within the fuse body that is designed to melt when excessive current passes through the fuse body, interrupting the flow of electricity to the downstream distribution system. Under certain conditions, the melting action and interruption technique will expel an arc out of the bottom of the fuse tab. To reduce the potential for ignition as a result of fuse operation, Pacific Power has identified alternate methodologies and equipment that do not expel an arc for installation within the FHCA. Pacific Power's standards for expulsion equipment replacement is based on Cal Fire's Power Line Fire Prevention Field Guide (2021 Edition). Pacific Power plans to proactively replace all expulsion fuses and other linked hardware within the FHCA in a systematic, prioritized manner as part of a multi-year effort. Currently, approximately 26,780 locations with expulsion fuses and other fuses expulsion equipment have been identified for replacement beginning in 2022 with completion anticipated in 2025. The following table and image depict the overall plan and yearly phasing of the work.

Table 18: Expulsion Fuse Replacement Plan

	2022[21]	2023 PLAN	2024 PLAN	2025 PLAN	TOTAL
FUSE REPLACEMENTS	1,000	10,776	8,919	6,085	26,780

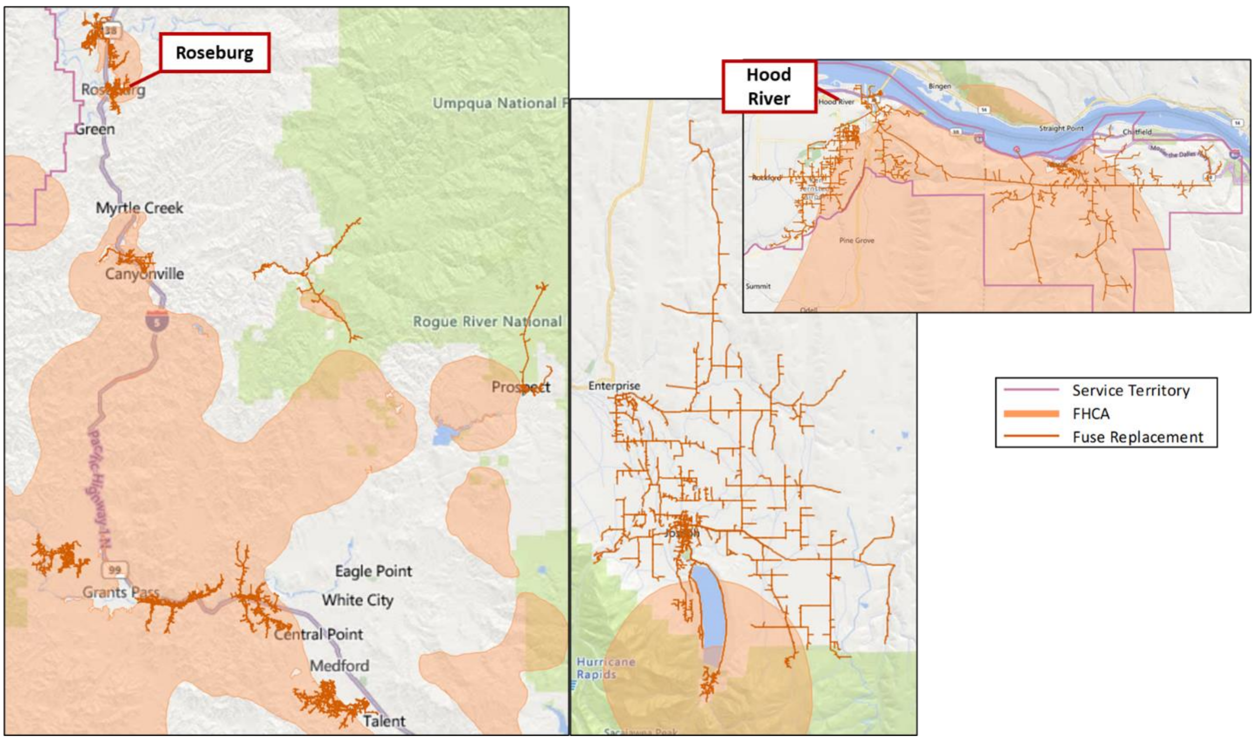


Figure 22: Oregon Expulsion Fuse Replacement Project

[21] 2022 values reflect forecasted values through the end of 2022 that were available when this plan was compiled.

4.4 FAULT INDICATORS

As described above in Section 4.2, Pacific Power is continuing to replace and upgrade electro-mechanical relays with microprocessor relays throughout the FHCA and enable the use of more refined settings for application during periods of greater wildfire risk, which is discussed further Section 6. To supplement these programs and generally mitigate the potential impacts to customers of these types of wildfire mitigation strategies, Pacific Power installed 2,156 fault indicators across the Oregon service territory, beginning with circuits that feed into the FHCA areas where EFR settings are most likely to be implemented. As Pacific Power continues to understand risk and implement mitigation programs such as EFR settings, the company may install additional fault indicators as needed to continue balancing the impact to customers and wildfire mitigation. The fault indicators are further described in Section 6.3 are depicted in the image below.

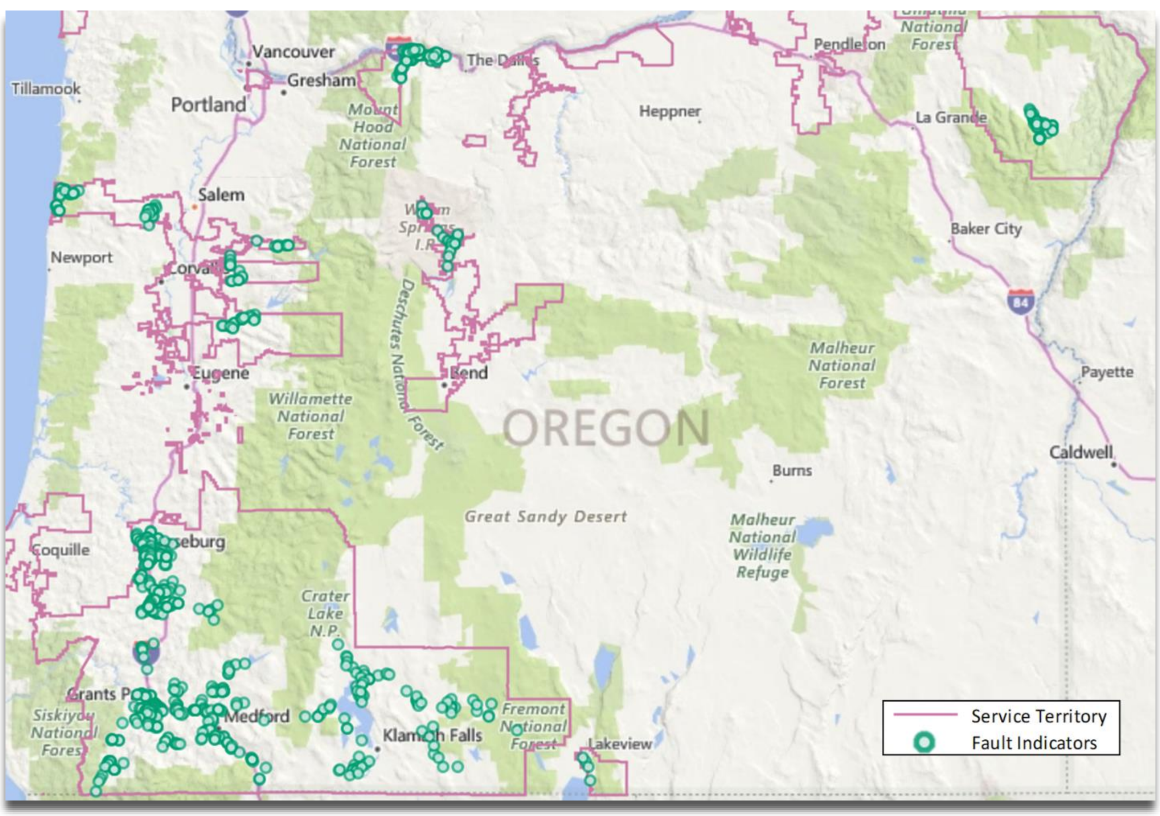


Figure 23: Fault Indicators Installed in 2022

5. Situational Awareness

As described in Section 1.1, Pacific Power uses the FHCA, the company's baseline risk map, layered with a risk driver analysis to inform strategic asset inspections, vegetation maintenance practices, and long-term system hardening solutions. However, as climate and weather patterns change, extreme weather events are predicted to become more frequent, and the potential exists for seasonal, dynamic, and/or isolated risk events to occur that compound or deviate from this baseline risk. Therefore, having an additional sophisticated, dynamic risk model grounded in situational awareness is pertinent to ensure electric utilities know when, where, how, and why to take abnormal action to mitigate the risk of wildfire.

Pacific Power's approach to situational awareness includes the acquisition of data to forecast and assess the risk of potential or active events to inform operational strategies, response to local conditions, and decision making. These key components, as outlined below, rely on a core team of utility meteorologists to guide, execute, and continuously evolve.

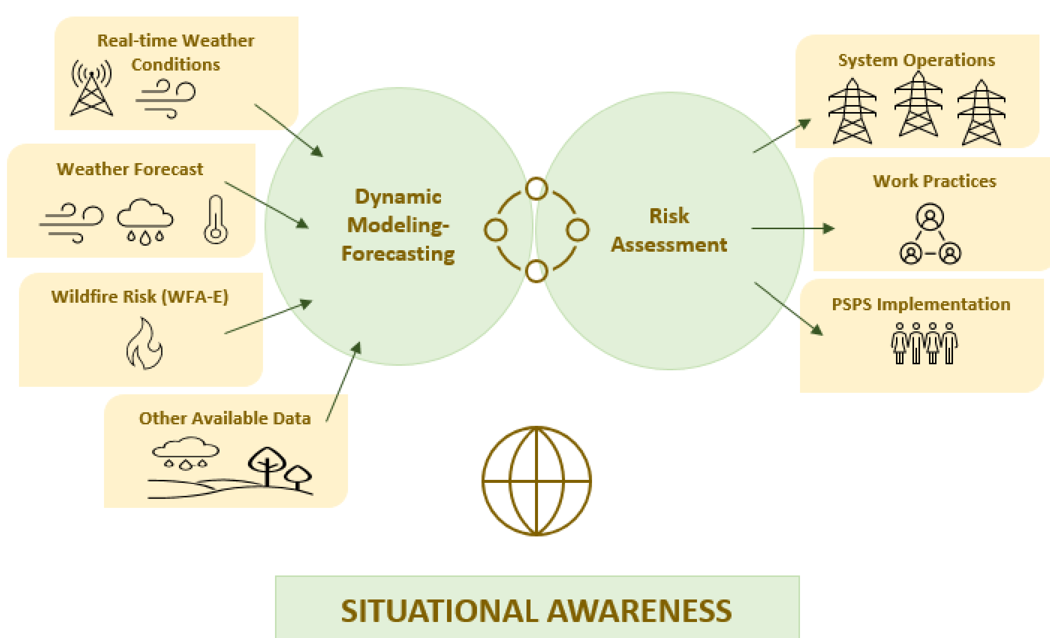


Figure 24: Overview of Situational Awareness

5.1 METEOROLOGY

As described above, the ability to gather, interpret, and translate data into an assessment of utility specific risk and inform decision making is key component of Pacific Power's situational awareness capability. To support this effort, Pacific Power has developed an experienced meteorology department within the company's broader emergency management department. This team consists of four full-time meteorologists, one data scientist, and one manager. The team's experience includes decades of fire weather forecasting for various government agencies such as the National Weather Service (NWS) and Geographic Area Coordination Center (GACC).

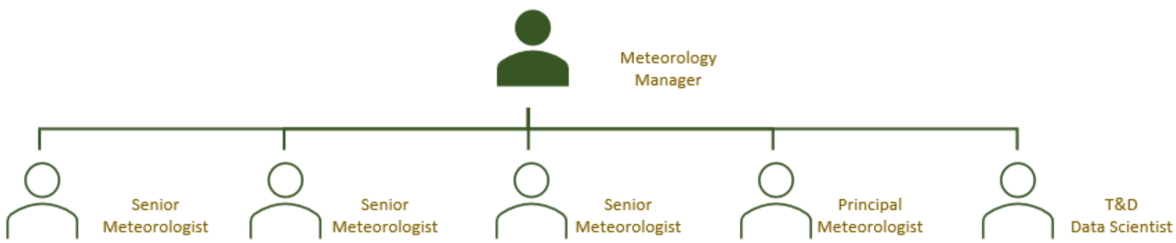


Figure 25: Meteorology Team

The objectives of this department are to supplement the company's longer term risk analysis capabilities (also referred to in this document as baseline risk modeling and described in Section 1.1) with a real time risk assessment and forecasting tool, identify and close any forecasting data gaps, manage day to day threats and risks, and provide information to operations to inform recommend changes to operational protocols during periods of elevated risk as depicted below.

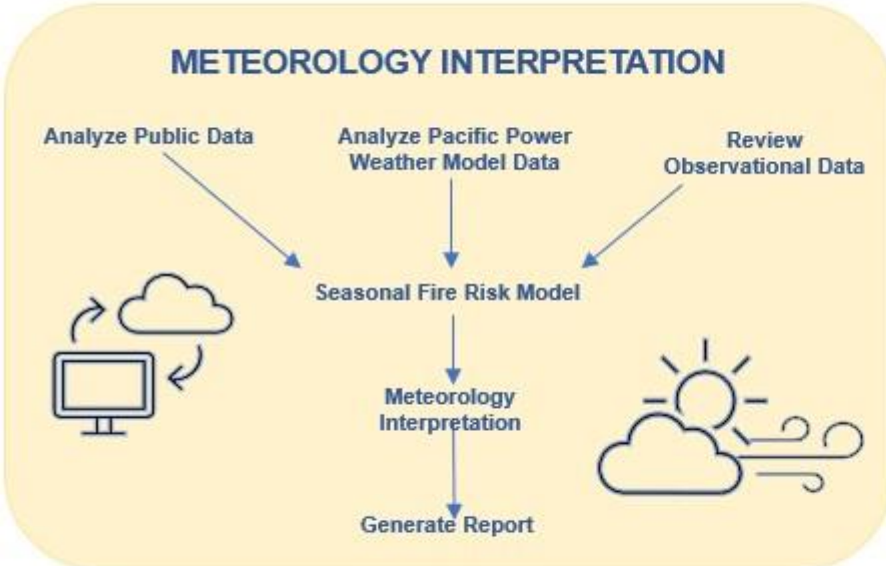


Figure 26: Meteorology Daily Process

Numerical Weather Prediction

The foundation of Pacific Power's Meteorology program is the creation of an impacts-based forecasting system consisting of an operational Weather Research and Forecasting (WRF) model and a complimentary 30-year WRF reanalysis across the company's entire service territory. Using the WRF reanalysis and other training data, Pacific Power plans to build and train machine learning models to improve its operational thresholds and convert the weather forecast into a prediction of system impacts.

Operational WRF Model: Pacific Power's Meteorology department has developed and is now utilizing a twice daily, 2km-resolution, hourly Weather Research and Forecasting (WRF) model, which produces a comprehensive forecast of atmospheric, fire weather, and National Fire Danger Rating System (NFDRS) parameters out to a timescale of 96 hours (about four days). The model's high resolution gives a much more complete picture of finer scale atmospheric features than available with most public four-day ahead timescale models. In addition, the WRF data is overlayed on the overhead distribution circuits and transmission lines along with other relevant utility asset data for further analysis.

30-Year WRF Reanalysis: Pacific Power's Meteorology department is actively developing a 30-year, 2km-resolution, hourly WRF reanalysis (to be completed by spring 2023). The 30-year WRF reanalysis uses the same configuration and contains the same weather, fire weather, and NFDRS parameters as Pacific Power's operational WRF to minimize any potential forecast biases between the two datasets. Once complete, this reanalysis data will be correlated with historical outage data and wildfire events using statistical and machine learning techniques to improve the company's weather-related outage and wildfire risk thresholds. Output from Pacific Power's operational WRF model can then be ingested by the company's machine-learning models and GIS tools to convert the daily forecast into potential system impacts and to map the intersection of fire weather and outage related risks across its service territory.

5.3 DATA ACQUISITION

Data acquisition, from both internal and external sources, is another key component of Pacific Power's situational awareness model.

Weather Station Network

Public weather data has been available for many years for reference. However, relying only on publicly available data can have limitations. When using publicly available weather data the utility doesn't have visibility in the maintenance and calibration records or standards used to maintain the weather station collecting the data. Additionally, the data collected frequency may not match the needed intervals for performing real time risk assessments and dynamic modeling. Finally, publicly available data may have geographic coverage gaps within the utility's service territory. When weather stations are owned by the utility the calibration date and usability of the data is known, the data reporting intervals can be adjusted to report more frequently, and the data can be used to inform real time operations. Additionally, weather stations can be installed and adjusted to pinpoint specifical locations needed to inform utility risk assessment.

For all these reasons Pacific Power is investing in a utility owned and operated weather station network within the company's service territory. The following image depicts the general weather station siting methodology.

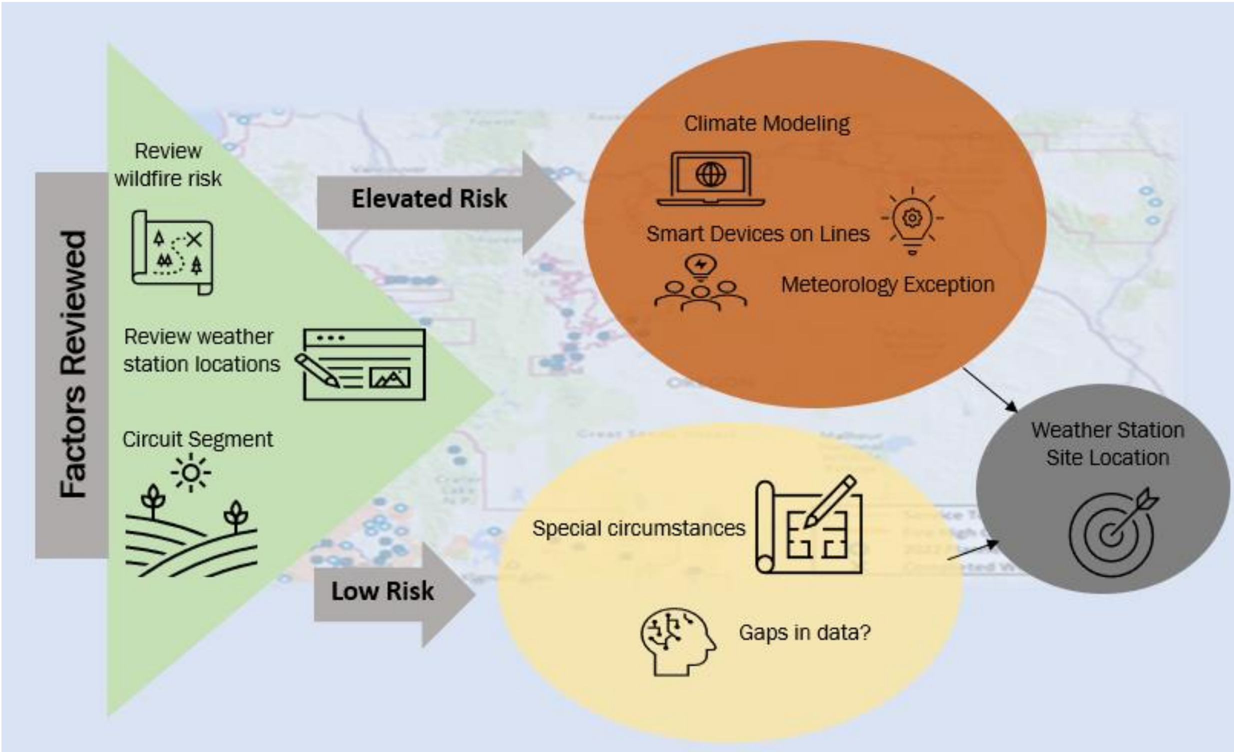


Figure 27: General Weather Station Siting Methodology

Currently, the weather station network in Oregon consists of 115 weather stations comprised of 105 micro stations and 10 portable weather stations. The micro stations are generally installed directly on utility infrastructure and the portable weather stations are available for deployment, as needed, during extreme weather events.

Weather station data is used to create a model of routine weather patterns in specific areas. Utilizing machine learning and artificial intelligence improves the forecasts specific to infrastructure, on or around, where the weather stations are installed. The improved modeling can allow better anticipation, when and where resources could be staged, to decrease restoration times during impactful weather events. Modeling impacts on the infrastructure is an important component of situational awareness, informing operational protocols and decision-making processes.

The weather station network buildout is in a phase of covering circuits within areas of elevated fire risk and wildland areas with 50 more weather stations expected to be installed over the next couple of years. There are expected to be about 200 weather stations by the end of 2024.

After the elevated risk circuits have weather station data the focus will transition to address gaps in data or in other locations discovered that would've been beneficial when making operational decisions. The current and planned weather stations are depicted below.

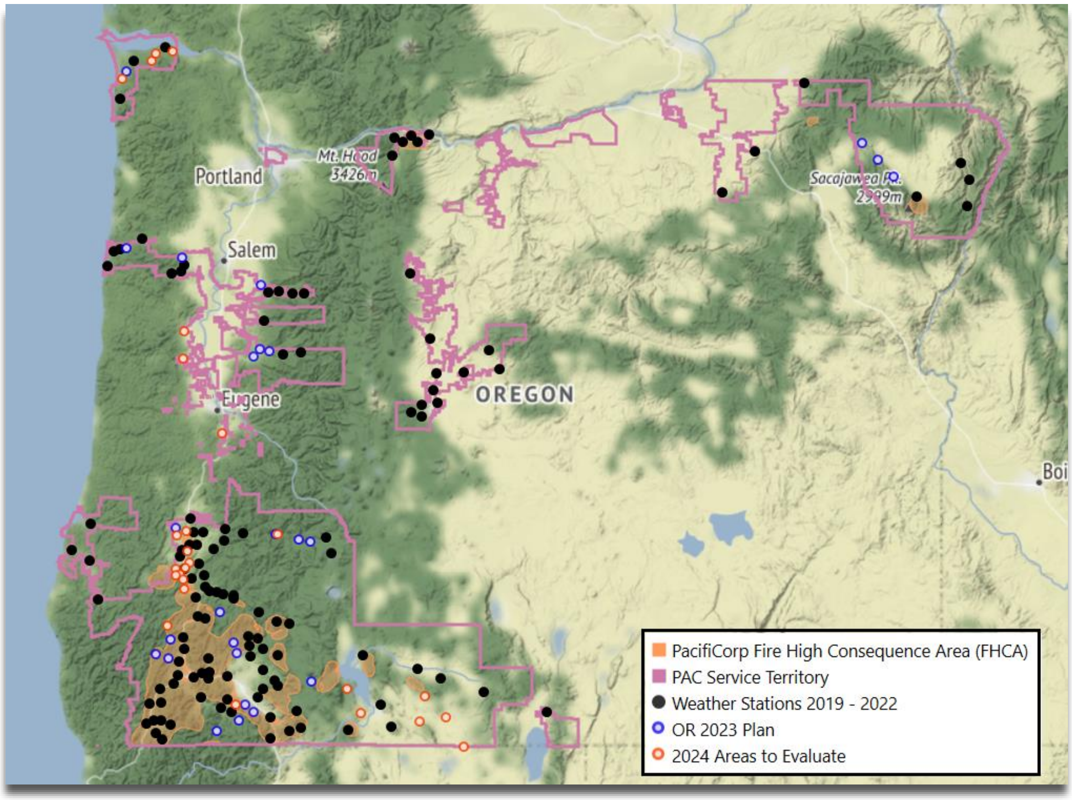


Figure 28: Pacific Power Oregon Weather Station Network (Complete & Planned)

The following table and image depict the overall plan and yearly phasing of the work.

Table 19: Weather Station Build Out Plan

	2022 ACTUALS[22]	2023 PLAN	2024 AREAS TO EVALUATE	TOTAL
New Weather Stations	86	47	25	158
Total OR Fleet	115	162	187	187

[22] 2022 Actuals include work forecasted through EOY 2022 and is subject to change.

Pacific Power's meteorology department will continue to evaluate the benefits of additional weather stations and anticipates that this program will continue to grow.

Data Inputs to Seasonal Wildfire Model

As described in Section 1.4, in 2022, Pacific Power procured an implemented a broader suite of wildfire risk modeling tools from Technosylva more commonly referred to as WFA-E (Wildfire Analyst Enterprise). In addition to the WRRM tool describes in Section 1.4, the WFA-E (Wildfire Analyst Enterprise) also includes FireCast and FireSim, two seasonal fire models, and is the model currently used by Pacific Power to forecast the risk of wildfire and the potential behavior of a wildfire should it occur. Technosylva, the company that developed and provided implementation and ongoing operational support for WFA-E, sources most of the data inputs for the Seasonal Wildfire Model which are generally described in Appendix A – Dynamic Modeling Data Inputs.

5.4 SEASONAL WILDFIRE RISK

FireCast performs millions of wildfire simulations daily across the company's six-state service territory to assess the fire risk in any given area. This output is also joined with a subset of distribution and transmission asset data to provide asset-specific wildfire risk and consequence forecasts. FireCast provides a 96 hour look ahead to discern if there is a risk of wildfire within that time period, where the risk is and where the greatest consequence is if there is a wildfire. FireCast also allows for comparison of forecast conditions to historical conditions in the operational area.

Real Time Impact Based Fire Modelling

FireSim, part of the WFA-E solution, is a simulation that can be run to forecast the potential fire behavior and spread from as little as one hour to up to a 96-hour period to assess the potential impact on populations, buildings, utility assets and other resources in the field. FireSim's model assumes no suppression efforts to slow the fire's spread and considers the following elements.

- **Initial Attack Assessment:** Assessment of how difficult initial attack will be for first responders and the probability of stopping the fire within the first operating period.
- **Population at Risk:** Number of people in the path of the fire and the timing of when the fire is likely to arrive at populations.
- **Assets at Risk:** Physical assets such as utility equipment, residential and commercial structures, barns, outbuildings etc. and the timing of when the fire is likely to arrive at assets.
- **Places at Risk:** These are locations identified on the maps that may not be physical assets but have other significance. These could include parks, reservoirs, cultural sites, campgrounds, etc. These locations are default locations from Google Earth Studio.
- **Weather and fuels conditions**: Wind speed, direction, fuel moisture content.

This multi-year effort, which will pull heavily from experience in California, will incorporate fire spread analysis and modelling with existing data, align with the Integrated Reporting of Wildland Fire Information (IRWIN) federal active wildfire incident reporting tool and ALERT wildfire cameras.

5.5 APPLICATION & USE

Pacific Power's meteorology team analyzes weather model data and risk modeling output to produce a district-based, weather-related system impacts forecast daily on business days. During periods of extreme risk, this assessment is performed daily, including weekends. This is combined with the team's district-based fire risk forecast as part of the meteorology team's System Impacts Forecast Matrix. See below.

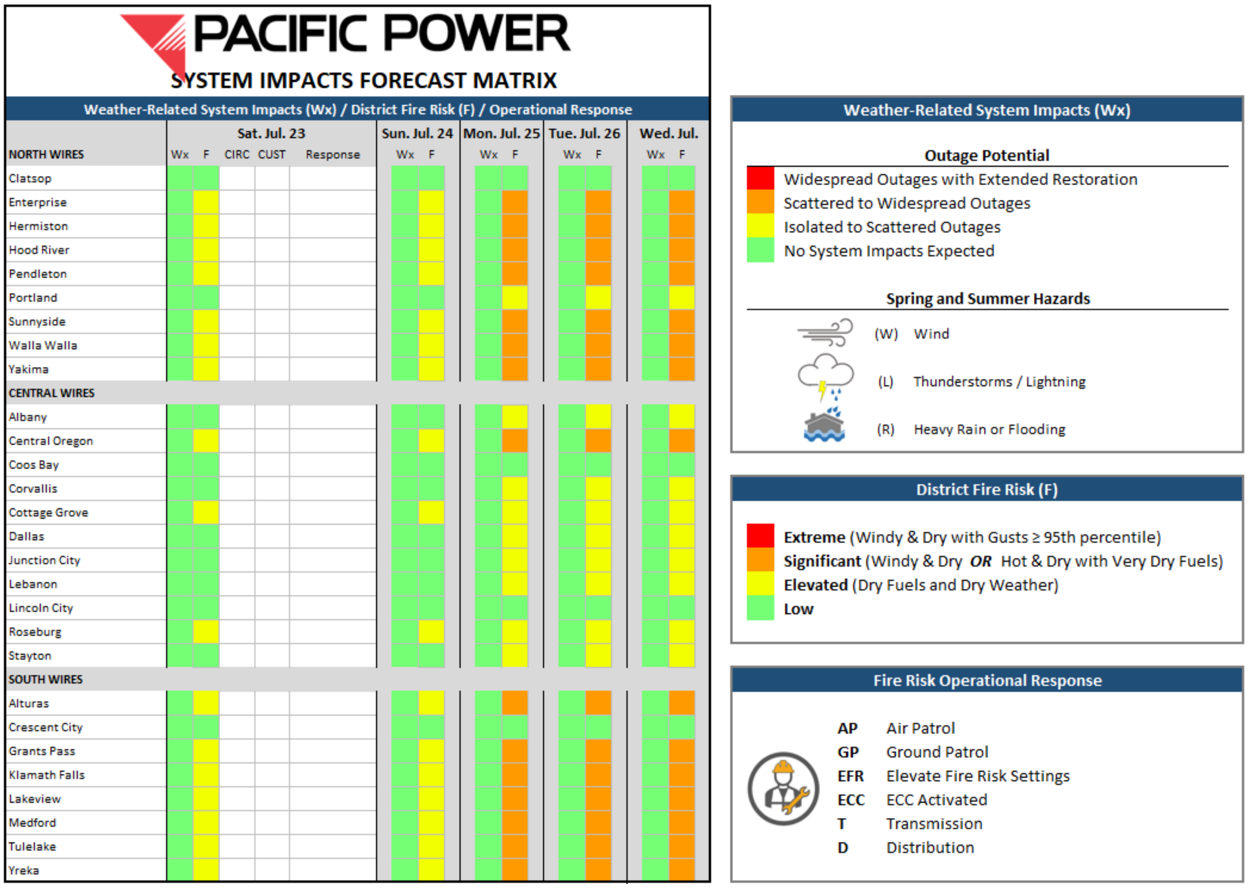


Figure 29: Daily System Impact Forecast Matrix

Assessing the Potential for Weather-Related System Impacts: Pacific Power has identified correlations between wind conditions and system performance through an analysis of outage records and past weather from Pacific Power's WRF reanalysis. Based on the early results of this analysis, Pacific Power can use weather forecast data from its own in-house WRF model to anticipate wind conditions that could lead to wind-related system impacts. In general, the data show that the probability of wind-related outages increases exponentially when wind gusts exceed the 95th percentile for a given location, though additional analysis is planned prior to the 2023 wildfire season.

Assessing the District Fire Risk: In 2022, Meteorology assigned a district-level wildfire risk based on an assessment of the Geographic Area Coordination Center's (GACC) 7-Day Significant Fire Potential product, publicly available fuels information, and weather forecast data from Pacific Power's WRF model. Wildfire risk is expressed using a four color-code scheme (green, yellow, orange, and red), with general inputs assessed and categorized as follows.

PacifiCorp Wildfire Risk	GACC 7-Day Significant Fire Potential	Fuels Considerations	Wind Gust Considerations
Little to No Wildfire Risk	Low or Little to No Risk		
Elevated Wildfire Risk	Low or Moderate	Dry	
Significant Wildfire Risk	Moderate	Very Dry	
	High Risk*	Dry or Very Dry	Max Gusts < 95th Percentile
Extreme Wildfire Risk	High Risk*	Dry or Very Dry	Max Gusts ≥ 95th Percentile

* Excludes Lightning or Recreation High Risk triggers

PacifiCorp Fuels	100-hr Dead Fuel Moisture	1000-hr Dead Fuel Moisture	Energy Release Component
Dry	Near or Below Average*		Near or Above Average*
Very Dry	≤ 10th Percentile	≤ 10th Percentile	≥ 90th Percentile

*Relative to the average fire season values for a given location

Figure 30: 2022 Approach to District Level Wildfire Risk Assessments

When moving into an elevated, significant, or extreme wildfire risk, Meteorology performs an additional review of fuels and fire weather forecasts and observations, including by using some or all of the additional metrics and methods outlined in the table below.

Table 20: Initial Weather, Fuel, and Wildfire Impact Assessment

Additional Considerations When Assessing Wildfire Potential	
Wildfire Consequence Modeling (WFA-E)	Millions of wildfire simulations are performed daily to map out potential wildfire risk and consequence across the service territory.
Fire Weather Watches or Red Flag Warnings	Has the National Weather Service issued a Fire Weather Watch or Red Flag Warning for the area in question?
High Resolution Fire Weather Forecasts (WRF)	Pacific Power's 2km WRF model produces a twice daily territory-wide forecast of fire weather and National Fire Danger Rating System (NFDRS) outputs 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 risk.
Fuels Conditions (Grasses, Live Fuels, & Dead Fuels)	Observations of the local fuels conditions including 1, 10, 100, and 1000-hr dead fuel moisture, herbaceous and woody live fuel moisture, tree mortality, Energy Release Component, etc.
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.
FHCA (Y/N)	Fire High Consequence Areas are pre-identified areas of elevated risk based on historical fires, climatology, geography, and populations

Prior to the onset of the 2023 fire season, Pacific Power plans to update the data inputs into its District Fire Risk categories using a recently developed Fire Potential Index (FPI). Developed by Technosylva for Pacific Power, the FPI quantifies the potential for large or consequential wildfires based on weather, fuels, and terrain. To accomplish this, Technosylva performed a detailed analysis of past weather from Pacific Power's WRF reanalysis, satellite-derived hotspot (wildfire) data from The Visible Infrared Imaging Radiometer Suite (VIIRS), and other environmental data. See general approach below.

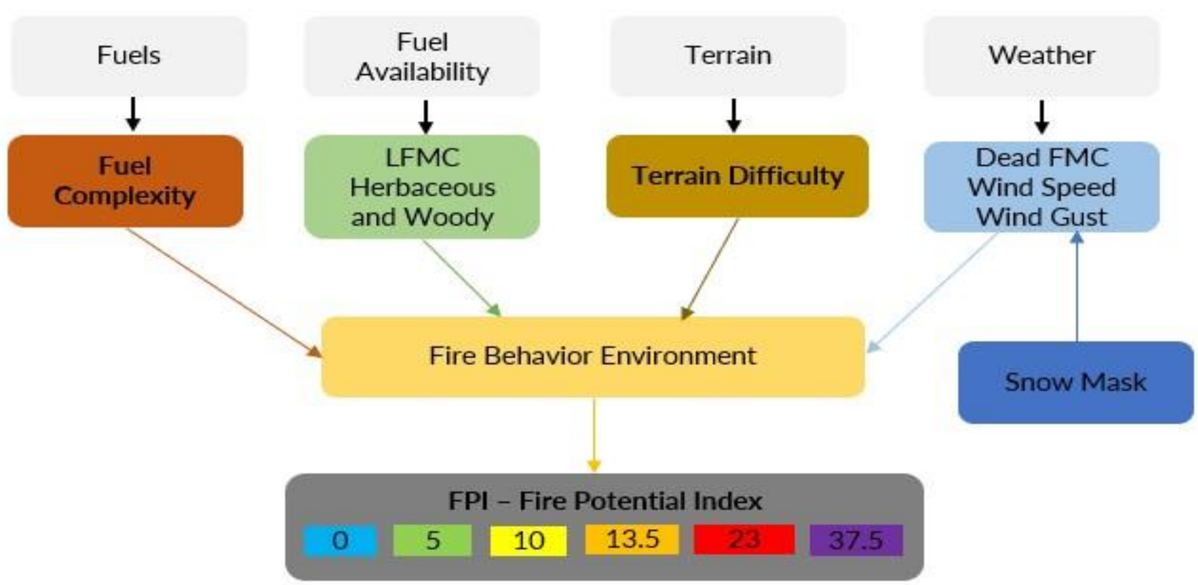


Figure 31: 2023 Fire Potential Index (FPI) Model

More specifically, VIIRS hotspot data was geospatially and temporally aggregated to create a database of high fire activity. For each of these fire days and fire locations, historical weather variables from Pacific Power's WRF reanalysis were retrieved and analyzed along with other environmental data on vegetation (fuel) and terrain. From this data, an artificial intelligence model was built and trained to estimate 3-hour potential fire activity by time and place using Pacific Power's operational WRF as the primary weather input. This approach aims to predict adverse fire spread conditions which could cause new fires to exceed fire suppression capabilities in the initial attack and become large or destructive.

Pacific Power recognizes that under certain conditions, wildfires can occur anywhere there is sufficient wildland vegetation to burn, even in historically low risk areas. For this reason, the District Fire Risk (and associated FPI inputs) is not limited to the FHCA but will include Pacific Power's entire service territory.

5.6 PUBLICLY AVAILABLE SITUATIONAL AWARENESS DATA

Pacific Power's weather stations and WRF model generate a considerable amount of data each day. In alignment with Staff's recommendations for greater transparency, Pacific Power makes this data available to its employees, customers, and public safety partners through a Situational Awareness website[23] alongside weather station observations and forecast data from other trusted government sources, including the National Weather Service. Combining weather station observations with forecast data allows Pacific Power to compare the real-time weather observations to the forecast data. Further, the wind climatology of each weather station is considered, with real-time and forecast wind conditions color-coded based on station-specific statistics such as 95th and 99th percentile values. All the above data are automatically updated on the website as new data is available and can be viewed in maps, tables, and meteograms. Figure 32 below includes sample material from the public website.

[23] See PacifiCorp (pacificorpweather.com)

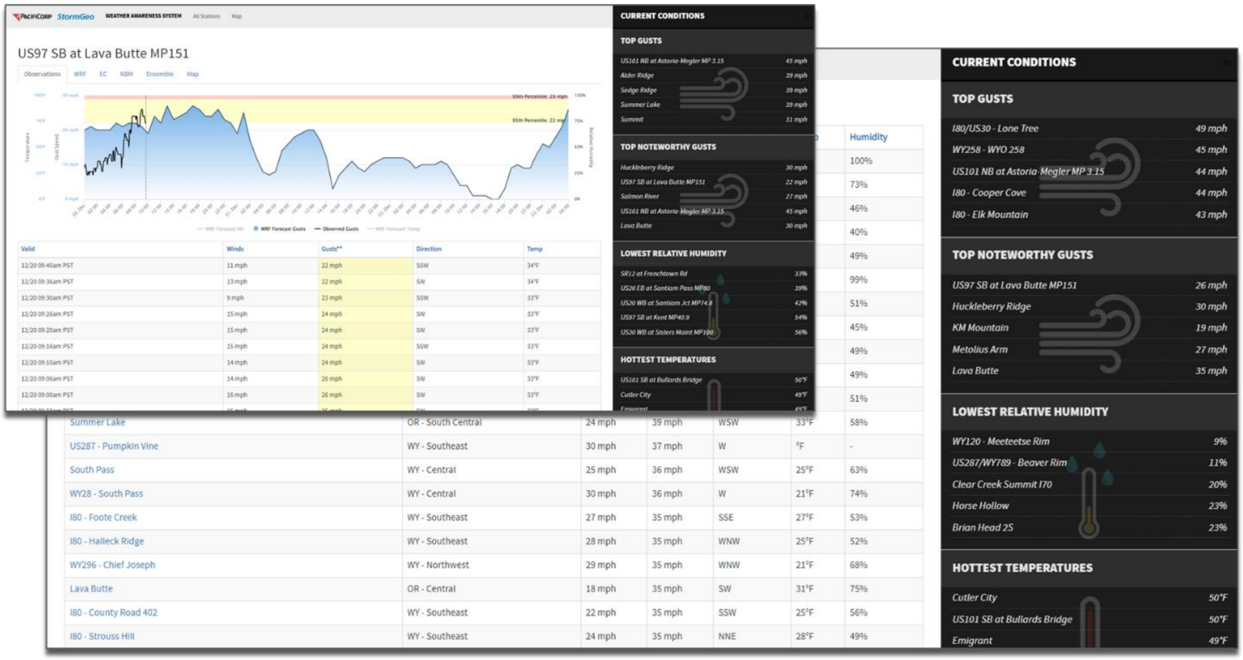


Figure 32: Sample Publicly Available Situational Awareness Information

This data is also ingested into an internal dashboard used for situational awareness internally during periods of high risk such as during a PSPS. This dashboard is customizable based on the scale of the event and includes station alert speeds or other decision points. In 2023, Pacific Power plans to add additional circuit details to this internal dashboard to improve visibility and situational awareness.

6. System Operations

Adjustments to power system operations can help mitigate wildfire risk. System operations adjustments generally include the modification of relay settings for protective devices on distribution lines or changes to line re-energization testing protocols described further in this section. These adjustments are not universally applied to power system operations because there are certain disadvantages in their use, especially because they may increase outage frequency and duration experienced by customers. In other words, a balance is required to provide customers with reliable power while still mitigating wildfire risk. To help balance these concerns, Pacific Power is deploying technologies such as fault indicators that are also discussed in the subsections below.

6.1 ELEVATED FIRE RISK SETTINGS

Line protective devices, such as line reclosers, are currently deployed on various transmission and distribution lines throughout Pacific Power's service territory. When a line trips open due to fault activity, reclosers can be programmed to momentarily open, allow the fault to dissipate, then reclose in an effort to test if the fault is temporary. The reclosing function gives the ability to restore service on a line that has tripped while maintaining the option to open again if the fault persists. If the fault is permanent, the recloser will operate and stay open (known as the "lock out" state) until the line has been deemed ready for re-energization. The image below generally depicts one potential configuration of a distribution circuit with multiple line reclosers installed.

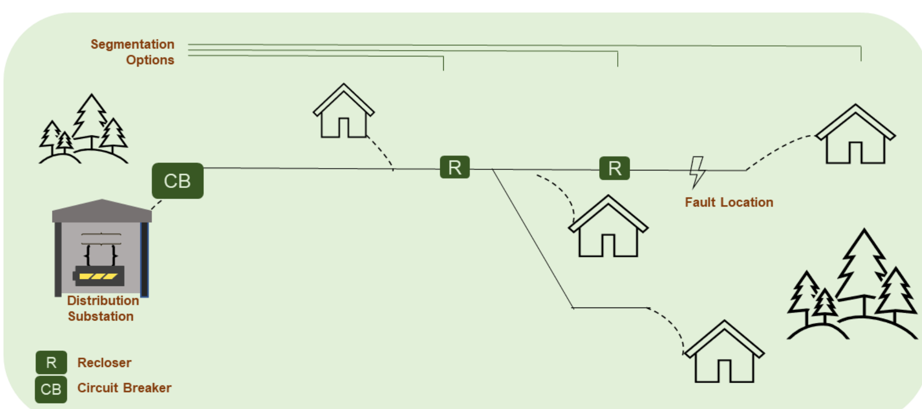


Figure 33: Example of Distribution Circuit with Multiple Reclosers

In general, recloser operation is beneficial because it reduces the number of sustained outages and improves customer reliability. The reclosing function, however, implicates some degree of ignition risk because additional energy can be released if a fault persists. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings to re-energize the line. If the fault is temporary in nature and is no longer present upon the reclose operation, the line will re-energize resulting in limited impact to customers. If the fault persists, however, reclosing can, depending on the circumstances, potentially result in arcing or an emission of sparks. Accordingly, a strategic balance between customer reliability goals and wildfire mitigation goals is required.

Pacific Power has used recloser disabling strategies on transmission lines for many years, and it has employed more frequent disabling of reclosers on transmission lines in recent years because of the increased wildfire risk. Pacific Power has been able to use these strategies without having too great of an impact on customer reliability. With wildfire risk continuing to increase, Pacific Power is implementing additional strategies on the distribution network, including the use of modified and more sensitive protection and control schemes, referred to as Elevated Fire Risk (EFR) settings.

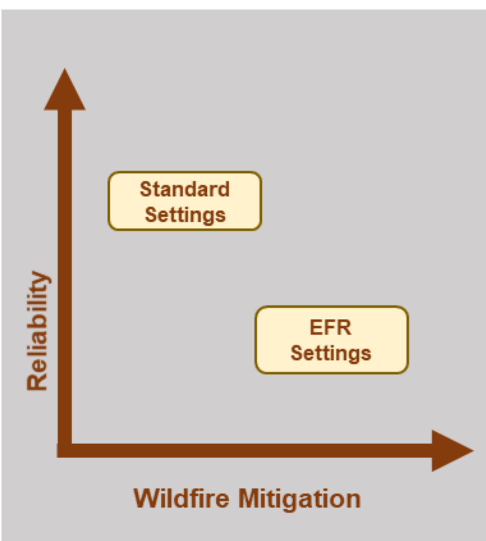


Figure 34: General Relationship between EFR Settings, Reliability, and Wildfire Mitigation

Such applications on the distribution network, however, tend to have a greater impact on customer reliability as depicted in Figure 34 and Pacific Power is exploring different strategic combinations to find the right balance.

To mitigate impacts to customer reliability, Pacific Power generally does not disable reclosing seasonally. Instead, Pacific Power leverages the daily risk assessment process and situational awareness reports described in Section 5.5 and takes a risk-based approach to the implementation of EFR settings. For example, when meteorological conditions of increased wildfire risk occur, an alternative operating mode may sometimes be used to reduce the number of reclose attempts, increase the open interval time between trip and reclose operations, or set the recloser to lock out upon a single trip event. In 2023, Pacific Power plans to continue evaluating situational awareness, customer outages and other information to further optimize the settings and implement EFR settings as needed.

6.2 RE-ENERGIZATION PRACTICES

Risk-based changes to re-energization practices is very similar to the implementation of EFR settings in that it also requires a balance between customer reliability and wildfire mitigation. If a breaker or recloser has "locked-out" – meaning that it has opened and no longer conducts electricity – a system operator or field personnel will sometimes "test" the line. To test the line, the system operator or field personnel will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability similar to the use of reclosing described in the previous section. At the same time, line-testing can potentially result in arcing or an emission of sparks if a fault has not yet cleared when the line is tested. To mitigate this risk, Pacific Power requires an appropriate level of patrol prior to line testing, depending on local circumstances. In 2023, Pacific Power plans to further incorporate situational awareness reports to continue informing re-energization protocols during periods of elevated risk.

6.3 OUTAGE RESPONSE TOOLS

Implementation of EFR settings can result in more frequent outages to customers. Additionally, introducing alternate re-energization practices that require incremental or augmented patrols after system faults can take a substantial amount of time. While sometimes warranted to reduce the risk of wildfire, Pacific Power recognizes the disruption this can have to customers and communities.

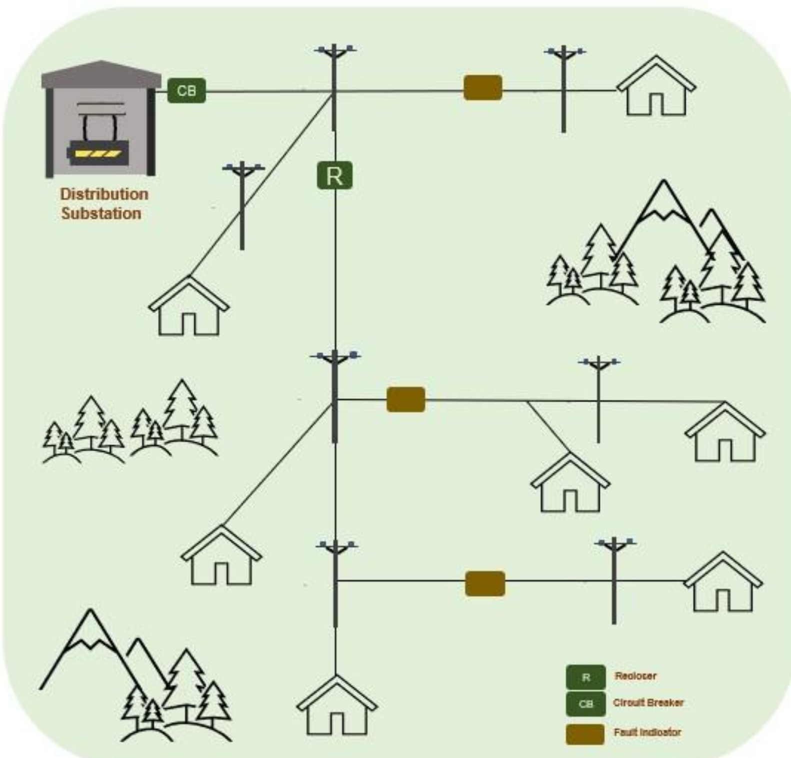


Figure 35: General Fault Indicator Configuration

The time it takes to patrol a line and overall impact to customers can be substantially reduced when the fault location can be determined. Therefore, as described in Section 4.4 and generally depicted in Figure 35, Pacific Power installed fault indicators in 2022 across the Oregon service territory, prioritizing circuits that fed into the FHCA areas where EFR settings are most likely to be implemented. When an outage occurs, these new tools are utilized by regional operators and field personnel to narrow down potential fault locations, optimize the deployment of resources, and expedite restoration.

As Pacific Power continues to understand risk and implement mitigation programs such as EFR settings, the company may install additional fault indicators as needed to continue balancing the impact to customers and wildfire mitigation.

7. Field Operations & Work Practices

During fire season, Pacific Power modifies field operations and work practices to further mitigate wildfire risk. Additionally, Pacific Power invests in tools and equipment to mitigate wildfire risk.

7.1 MODIFIED PRACTICES & WORK RESTRICTIONS

As a part of the situational awareness reports and briefings prepared by the meteorology department, the operations department within Pacific Power considers the local weather and geographic conditions that may create an elevated risk of wildfire. These practices are targeted to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response and outage restoration.

Pacific Power personnel working in the field during fire season mitigate wildfire risk through a variety of tactics. Routine work, such as condition correction and outage response, poses some degree of ignition risk, and, in certain circumstances, crews modify their work practices and equipment to decrease this risk. In the extremely unlikely event that a fire ignition occurs while field crews or other Pacific Power personnel are working in the field (collectively "field personnel"), such field personnel are equipped with basic tools to extinguish small fires.

Figure 36: Lineworkers Performing Work

Pacific Power is able to mitigate some wildfire risk by managing the way that field work is scheduled and performed. To effectively manage work during fire season, area managers regularly review local fire conditions and weather forecasts provided to them as part of Pacific Power's monitoring program – discussed in the situational awareness section.

During fire season generally, operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods of heightened fire weather conditions. If essential work needs to be performed in the FHCA and other areas with appreciable wildfire risk, certain restrictions may apply, including:

Hot Work Restrictions. Operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.

Time of Day Restrictions. Operations managers are encouraged to consider using alternate work hours to accommodate evening and night work, when there may be less risk of ignition.

Wind Restrictions. Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.

Driving Restrictions. Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.

Worksite Preparation. If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in the FHCA. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Additional Labor Resources

To implement some of the wildfire mitigation programs generally described above and in Section 6, additional labor resources and field personnel time is often required to (a) support system operations in assessing localized risk and administering EFR settings and (b) responding to outages during fire season with additional patrols and coordination.

Under normal operating procedures, system operators and field personnel work together on a daily basis to manage the electrical network. In many situations, system operators depend on field personnel to gather information and assess local conditions. As discussed in Section 6, there are system operations procedures during wildfire season for implementing EFR settings and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more frequently than would otherwise be required under normal operating procedures. The requests from system operators may be varied, ranging from a simple phone call to confirm that it is raining in a particular area, to a much more time-intensive request, such as a full line patrol on a circuit.

Field personnel may also spend some additional time when responding to an outage during fire season. As discussed in Section 6.2, a heightened risk exists with traditional restoration practices. To mitigate this risk, field operations may perform some amount of line patrol on certain de-energized sections of the circuit, notably during fire season and particularly in the FHCA dependent on current conditions at the work site and the duration of the restoration work. Depending on the circumstances, this extra patrol might be done just before or just after re-energizing the line. Typically, this type of line patrol does not involve a close inspection of any particular facility; instead, it is a quick visual assessment specifically targeted to identify obvious foreign objects that may have fallen into the line during restoration work.

In 2022, Pacific Power began tracking the activities and costs associated with this program more discretely, which is now reported and forecasted in Section 13.

7.2 EQUIPMENT AND TOOL PURCHASES

In addition to changes in work practices, Pacific Power invests in tools and equipment to mitigate wildfire risk. These investments include (1) mobile communication devices, (2) vehicles, (3) personal suppression equipment, and (4) water trailers.

Compact Rapidly Deployable Cell on Wheels (COW)

Pacific Power operates and serves customers in very rural locations, some of which have limited to no cellular connectivity back to the local district office and/or the control center. During large disasters, such as wildfire events, Pacific Power field personnel need to be able to communicate quickly and effectively to maintain safe operation of its system and support emergency response and restoration activities. Therefore, Pacific Power is currently procuring three (3) compact, rapidly deployable Cell on Wheels (COW) devices. This equipment, which is shown in Figure 37, will be strategically staged at Pacific Power's service centers throughout Oregon for use during emergencies to improve communication capabilities to the control center, base camp, and/or management when cell coverage is unavailable. This equipment will also enable communication when there is a loss of communication due to infrastructure failure for SCADA access, WAN, and portable radios. Overall, this equipment will improve emergency restoration activities and mitigate impacts to customers.

Figure 37: Rapidly Deployable Cell on Wheels (COW)

Vehicles

Vehicles can be a source of ignition. As discussed above, operations personnel are instructed to stay on designated roads during fire season, as feasible, and to avoid vegetation which could contact the undercarriage of parked vehicle. To further mitigate any wildfire risk associated with the use of vehicles, Pacific Power plans to convert, over time, the vehicle exhaust configuration of work trucks. Some vehicles in districts with the greatest amount of FHCA will be strategically converted. Long term, when new vehicles are purchased, Pacific Power plans to purchase trucks with a vehicle exhaust configuration which minimizes ignition risk.

Basic Personal Suppression Equipment

Personal safety is the first priority, and Pacific Power field personnel are encouraged to evacuate and call 911 if necessary. Field personnel working in the FHCA maintain the capability to extinguish a small fire that ignited while they are working in the field. Field personnel should attempt suppression only if the fire is small enough so that one person can effectively fight the fire while maintaining their personal safety. All field personnel working in the FHCA during fire season will have basic suppression equipment available onsite, because field utility trucks typically carry the following equipment: (1) fire extinguisher; (2) shovel; (3) Pulaski; (4) water container; and (5) dust mask. The water container should hold at least five gallons and may be a pressurized container or a backpack with a manual pump (or other).

Water Trailer Resources

Pacific Power has water trailers that field operations use to mitigate against wildfire risk. For clarity, these resources are not dispatched to reported fires (i.e., like a fire truck). Instead, Pacific Power resources are strategically assigned to accompany field personnel if conditions warrant. For example, if it is necessary to perform work in the FHCA during a period in which there is a Red Flag Warning, Pacific Power field operations may schedule a water trailer to join field personnel working in the field. As discussed above, the water trailer can be used to help prep the site for work. By watering down dry vegetation in the work area, any chance of an ignition can be minimized. In the extremely unlikely event there was an ignition, the water trailer could be used to assist in the suppression of a small fire.

Three water trailers have been delivered in Oregon, one of them is located in Medford, and the other two in Portland area.

8. Public Safety Power Shutoff (PSPS) Program

Pacific Power may de-energize power lines as a preventative measure during periods of the greatest wildfire risk. This practice is referred to as “proactive de-energization” or is more commonly known as a “Public Safety Power Shutoff” or “PSPS.” The decision to implement a PSPS is based on extreme weather and area conditions, including high wind speeds, low humidity, and critically dry fuels. A PSPS event is implemented as a last resort and is intended to supplement – not replace – existing wildfire mitigation strategies. The general process is described below.

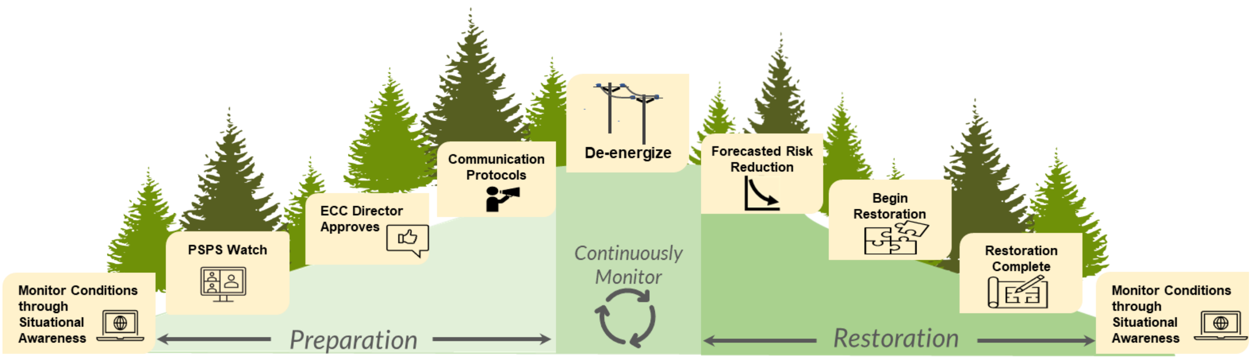


Figure 38: PSPS Overview

The following subsections describe Pacific Power’s program in greater detail. Many of the program elements revolve around the successful execution of a PSPS event, while other elements bolster decision-making, mitigate the potential impact of a PSPS event, or help to avoid use of the tool altogether.

8.1 INITIATION

As discussed in Section 5.5, situational awareness reports are generated daily during business days by the meteorology department to aid in decision making during periods of elevated risk. During periods of extreme risk such as PSPS assessment and activation, these reports are generated daily, including weekends. These reports identify where fuels (dead and live vegetation) are critically dry, where and when critical fire weather conditions are expected (gusty winds and low humidity), and where and when the weather is forecast to negatively impact system performance and reliability. It is the intersection of these three triggers that result in the potential for a PSPS event.

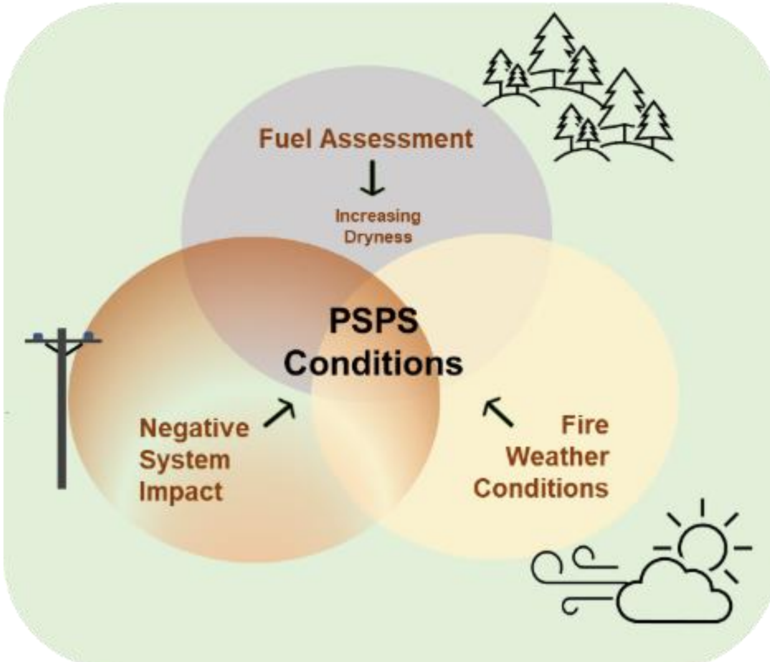


Figure 39: PSPS Assessment Methodology

Assessing the Potential for a PSPS

As discussed in Section 5.5 and above, meteorology generates a daily weather briefing which includes a System Impacts Forecast Matrix for Pacific Power's entire service territory. This matrix includes a district-level forecast of weather-related outage potential and fire risk. An example was included in Figure 29 of Section 5.5 When the forecast matrix indicates a significant or extreme wildfire risk in any district, Emergency Management schedules a coordination meeting to discuss circuits of concern and the appropriate operational response, up to and including PSPS. PSPS is typically discussed and/or considered when the forecast matrix indicates a combination of wind-related outage potential and extreme wildfire risk in the same district.

When the district fire risk is significant or extreme, Meteorology will use a combination of its WRF and outage models, Technosylva's WFA-E, and subject matter expertise to identify circuits of concern.

8.2 DE-ENERGIZATION WATCH PROTOCOL

Pacific Power actively monitors real-time weather conditions and endeavors to provide customers with additional notifications if de-energization is likely. When real-time observations and weather forecasts indicate extreme risk is forecasted, the de-energization watch protocol is initiated which includes activation of an “Emergency Coordination Center” (ECC), communication with local Public Safety Partners, and implementation of additional monitoring activities.

The ECC is staffed by a specialty group of company representatives who assemble during de-energization warning and implementation to provide critical support to operational resources through the collection and analysis of data. The ECC makes decisions to maintain the safety and reliability of the transmission and distribution system and helps facilitate cross-organization incident coordination. The ECC is led by an ECC Director and has the support of a safety officer, a joint information team, emergency management, meteorology and operational stakeholders representing field operations, system operations, vegetation management, engineering, and other specialties.

Upon activation of the ECC, Pacific Power emergency management gathers input from public safety partners to properly characterize and consider impacts to local communities. The ECC also sends advance notifications to the operators of pre-identified critical facilities, partner utilities, and adjacent local Public Safety Partners. The Pacific Power customer service team then coordinates through the ECC to confirm customer lists for the subject area to develop a communication plan for those customers potentially impacted.

Local assessments of lines may occur during a PSPS watch by way of various methods depending on the accessibility of locations, the reliability of the line, area conditions and other factors. The ECC reviews various factors and may deploy crews to perform these assessments in the field or may remotely monitor from the operations center.

Because of the public desire for reliable electric service, together with public safety concerns associated with de-energization, a PSPS is a measure of last resort and is disfavored. Nonetheless, consistent with existing regulations and the general mandate to operate the electrical system safely, the ECC has discretion to determine when a PSPS is appropriate. The

ECC Director will consider all available information, including real-time feedback and other considerations from other ECC participants and field operations to determine whether PSPS should be executed. Additionally, the ECC Director may decide to further refine the PSPS areas described above. As a matter of practical reality, the ECC Director cannot know whether a PSPS will prevent a utility-related ignition. If a PSPS is not implemented and an ignition occurs, the ignition itself is not proof that a PSPS should have been implemented. Likewise, if a PSPS is implemented, the event itself does not prove that an ignition that would have otherwise occurred was prevented.

8.3 DE-ENERGIZATION PROTOCOL

When a PSPS event is initiated, an action plan is prepared to include affected location details, event timing and projected event duration. Once approved by the ECC Director, an internal notification is sent to initiate appropriate notifications to customers, critical facilities, Public Safety Partners, regulatory organizations, large industrial customers and required field and system operations team members. Preparations also begin for the opening Community Resource Centers (CRC) as needed and additional field resources may be deployed or staged accordingly. Conditions are continually monitored; when PSPS conditions are no longer exceeded, the lines are patrolled and assessed for damage to begin the process of re-energization.

8.4 COMMUNICATION PROTOCOL

Pacific Power recognizes that adequate and clear communication is a key component to the successful implementation of a PSPS event, and Pacific Power will always strive to provide as much notice as practical to impacted parties (as described in the following section). Nonetheless, PSPS decisions are made based on weather forecasts, and weather can change quickly or dramatically with little forewarning, requiring some degree of balancing in communication protocols. Accordingly, advanced notice may not always be possible.

Public Safety Partners and Critical Facilities

Public Safety Partners are an essential component to any communication plan during an event. They provide essential insight into the geographic and cultural demographics of the affected areas to advise on protocols to address limited broadband access, languages, medical needs and vision or hearing impairment. Pacific Power's initial communication with local public safety agencies starts as early as possible when weather forecasts indicate a PSPS event is possible. Proactive communications to entities such as non-emergency dispatch centers, emergency management, fire agencies and law enforcement agencies allow those disciplines to prepare for anticipated operational impacts internally and mitigate any community-wide impacts that may occur as a result of de-energization. Collaboration with these agencies supports impact reduction of de-energization and communicates information regarding the impacted areas and expected event duration.

Upon activation of the ECC, emergency management resources coordinate, as appropriate, with local, county, tribal and state emergency management to provide information through the assigned representative of the agency. ECC assigned staff provide event details including estimated timing and event duration, potential customer impacts, and GIS shapefiles which include PSPS boundaries for areas subject to de-energization consistent with OAR 860-300-0050(1)(b). Throughout a PSPS event, Pacific Power's emergency management group maintains regular communication with local, regional and state emergency responders, mutual assistance groups, tribal emergency managers, and the State of Oregon Emergency Coordination Center through Emergency Support Function (ESF) 12 - Utilities. The company will support efforts to send out emergency alerts and status updates, as appropriate, until restoration efforts begin. Critical facilities are particularly vulnerable to the impact of PSPS events. Pacific Power emergency management maintains a list of critical facilities within its service territory and, upon activation of the ECC, will work to establish and maintain direct contact with these facilities' emergency points of contact to provide projected PSPS timing, estimated duration, regular status updates, and restoration notifications consistent with OAR 860-300-0050(1)(c). Additionally, Pacific Power will provide, where possible, will provide GIS shapefiles to communications facility operators in the areas of potential impact.

During a PSPS event, Pacific Power recognizes the importance of providing additional geographical details of the affected area and plans to provide these details to Public Safety Partners through a secure web-based Public Safety Partner portal. The Public Safety Partner portal is planned to be a secure, map-centric application that will host information regarding critical facilities and infrastructure like GIS files for location, primary/secondary contact information, and known backup generation capabilities. The portal is currently under development and discussed further in Section 9.

Customers

The Pacific Power PSPS webpage[24] provides timely and detailed information regarding potential and actual PSPS events for a specific location. Pacific Power's website has the bandwidth to manage site traffic under extreme demand; and has implemented bandwidth capacity to a level that will allow for increased customer access while maintaining site integrity. For example, the Wildfire Safety and PSPS webpages were successfully visited by over 14,000 people during the 2022 PSPS event without issue. The PSPS webpage provides visitors with an interactive map where users can input an address to see if a residence or business could be affected by a PSPS. When a potential PSPS is announced, the map will be updated to show geographic boundaries of potentially impacted areas. The boundaries will be colored yellow, or "Watch" prior to de-energization, then red or "Event" once de-energization occurs. The website is easily accessible by mobile device, and the Pacific Power 'app' is available for mobile devices, which allows customer access to real-time outage updates and information.

To ensure that outreach is provided in identified prevalent languages, Pacific Power delivers wildfire safety-specific communications including brochures, handouts, and bill messages translated into Spanish; a message in nine languages – which includes Chinese traditional, Chinese simplified, Tagalog, Vietnamese, Mixteco, Zapoteco, Hmong, German and Spanish – is included on the company's wildfire safety website pages that states "A customer care agent can speak with you about wildfire safety and preparedness. Please call 888-221-7070."; and customers with specific language needs can contact the company's customer care number and request to speak with an agent that speaks their language. Pacific Power employs

[24] See [Public Safety Power Shutoff (pacificpower.net)](https://www.pacificpower.net/psps) (https://www.pacificpower.net/psps)

Spanish-speaking customer care professionals and contracts with a 24/7 translation service that translates communications in real-time over the phone in hundreds of languages. Company customer care agents have access to and training with wildfire safety and preparedness and PSPS-related communications and can facilitate a conversation between the customer and translation service to ensure the customer receives the wildfire safety and preparedness and PSPS-related information they need.

Pacific Power's communications plan also includes procedures which ensure appropriate notifications (additional if time allows) to customers with serious medical conditions. Pacific Power leverages insight from public safety partners and customer records to pre-identify these customers. Upon activation of the ECC, Pacific Power will attempt, time and circumstances allowing, to make personal outbound calls with known vulnerable customers who utilize life support equipment.

The communication plan allows for informational updates to customers using multiple methods of communication. Direct customer notifications are made by way of outbound calls, text messaging and email notifications. Customers will receive an outbound call - when possible - within 48 hours of a potential PSPS event, 24 hours prior to de-energization, 1-4 hours prior to de-energization, at the commencement of the event, at the beginning of the re-energization process and upon the event conclusion. Additional methods of notification include the use of social media sites including Facebook and Twitter. Upon activation of the ECC, and following appropriate customer notifications, the public information officer will distribute press releases to news outlets that serve the affected areas. Regular updates across all available channels are distributed as they are available, and the public information officer will manage press inquiries as appropriate.

In making the customer notifications described above, Pacific Power provides a statement of the impending PSPS execution, the estimated date, time and duration of the forecasted event, a 24-hours means of contact for customer inquiries, links to pertinent PSPS websites, event status updates, and re-energization expectation notices.

Notification Timing

When there is a potential PSPS event forecast, customers and local government representatives will be provided with advanced notice; if feasible, notifications will begin 72 or 48 hours in advance of a potential de-energization event. If this is not possible due to rapidly changing weather conditions, or other emerging circumstances, the notification process will begin as soon as possible. Additional notice will be provided at appropriate times, as conditions are monitored and depending on the circumstances. There is some degree of balancing required. Customers generally want ample advance notice of any actual de-energization. At the same time, recognizing that weather forecasts are inherently speculative, it is possible to overburden customers with notices of potential PSPS events that never materialize, especially remembering that the company's fundamental business objective is to keep the grid energized except under the most extreme conditions.

The table below illustrates Pacific Power's planned PSPS notification timeline for notifications sent to customers, public safety partners and operators of critical facilities. Timelines may be reduced if rapidly changing conditions do not allow for advance notification consistent with OAR 860-300-0050. In these cases, the company will make all notifications as promptly as possible.

Table 21: PSPS Notification Timeline Summary

48-72 Hours Prior	De-energization Warning to Public Safety Partners & Operators of Critical Facilities
24-48 Hours Prior	De-energization Warning
1-4 Hours Prior	De-energization Imminent / Begins
Re-energization Begins	Re-energization Begins
Re-energization Completed	Re-energization Completed
Cancellation of Event	De-energization Event Canceled *(if needed)*
Status Updates	Every 24 hours during event *(if needed)*

8.5 COMMUNITY RESOURCE CENTERS

Pacific Power is aware of the potential impacts of PSPS events to customers, business, and communities and plans to provide community support through Community Resource Centers (CRCs). By taking advantage of established relationships with community and public safety partners, Pacific Power may activate a CRC in an impacted area, to give community members and businesses access to items that may be affected by the interruption of electrical service. The services, which vary across CRCs, may include:

- Potable water
- Shelter from hazardous environment
- Air Conditioning
- Seating and tables
- Restroom facilities
- Refrigeration for medicine and/or baby needs
- Interior and area lighting
- On-site security
- Communications including internet, Wi-Fi, cellular access, and satellite phone
- Television and radio
- On-site medical support (where available)
- Charging stations for cellular devices, radios and computers

Community resource centers adhere to all existing local, county, state or federal public health orders and will have personal protective equipment available on site for customers if needed. Pacific Power, when possible, will activate a community resource center during a public safety power shutoff event. Local emergency management and community-based organizations will be notified as appropriate and with advanced notice, generally three days prior to the event – when possible.

Community resource center activation timing, protocols and locations are discussed with area emergency management and community-based organizations during emergency management workshops and tabletop exercises. Pacific Power emergency management maintains established relationships with these organizations to continuously improve upon its emergency management practices.

Table 22 below includes the brick-and-mortar CRC locations currently identified in Oregon.

Table 22: Brick and Mortar Community Resource Centers

CRC	General Area	Address	County
Glendale Elementary School	Glendale	100 Pacific Avenue Glendale, OR	Douglas
Tri-City Fire Department	Riddle Myrtle Creek	140 S Old Pacific Hwy Myrtle Creek, OR	Douglas
Winchester	Winchester	780 NE Garden Valley Blvd Roseburg, OR	Douglas
Columbia Gorge Community College	Hood River	1730 College Way Hood River, OR 97301	Hood River
Greenspring's Fire Station	Cascades-Siskiyou	11471 OR-66 Ashland OR 97520	Jackson
Shady Cove Library	Shady Cove	22477 OR-62 Shady Cove, OR 97539	Jackson
Shady Cove City Hall	Shady Cove	22451 OR-62 Shady Cove, OR 97539	Jackson
Patrick Elementary School	Fielder Creek and South Rogue River	1500 2nd Ave Gold Hill, OR 97525	Jackson
Selma Community Center	Cave Junction	18248 Redwood Hwy Selma, Oregon 97538	Josephine
Illinois Valley High School	Cave Junction	625 E River St Cave Junction, OR 97523	Josephine
Bear Hotel	South Rogue River	2101 NE Spalding Ave. Grants Pass, OR 97526	Josephine
Sportsman Park	South Rogue River	7407 Highland Ave. Grants Pass, OR 97526	Josephine
Redwood Christian Center	South Rogue River	4995 Redwood Ave Grants Pass, OR 97527	Josephine
Jerome Prairie Transition Center	Jerome Prairie	2555 Walnut Ave Grants Pass, OR 97527	Josephine
Jerome Prairie Community Hall	Jerome Prairie	5368 Redwood Ave. Grants Pass, OR 97527	Josephine
Jerome Prairie Bible Center	Jerome Prairie	2564 Walnut Ave Grants Pass, OR 97527	Josephine
Merlin Community Park	Merlin	100 Acorn St, Merlin, OR 97532	Josephine
Fleming Middle School	Merlin	6001 Monument Dr, Grants Pass, OR 97526	Josephine
Manzanita Elementary School	Merlin	310 San Francisco St, Grants Pass, OR 97526	Josephine

CRC	General Area	Address	County
Sunny Wolf Charter School	Glendale	100 Ruth Ave, Wolf Creek, OR 97497	Josephine
Wolf Creek Inn, Hugo	Glendale	100 Front St, Wolf Creek, OR 97497	Josephine
Glendale Elementary	Glendale	100 Pacific Avenue, Glendale, OR 97422	Josephine

These brick-and-mortar locations are shows in Figure 40 below.

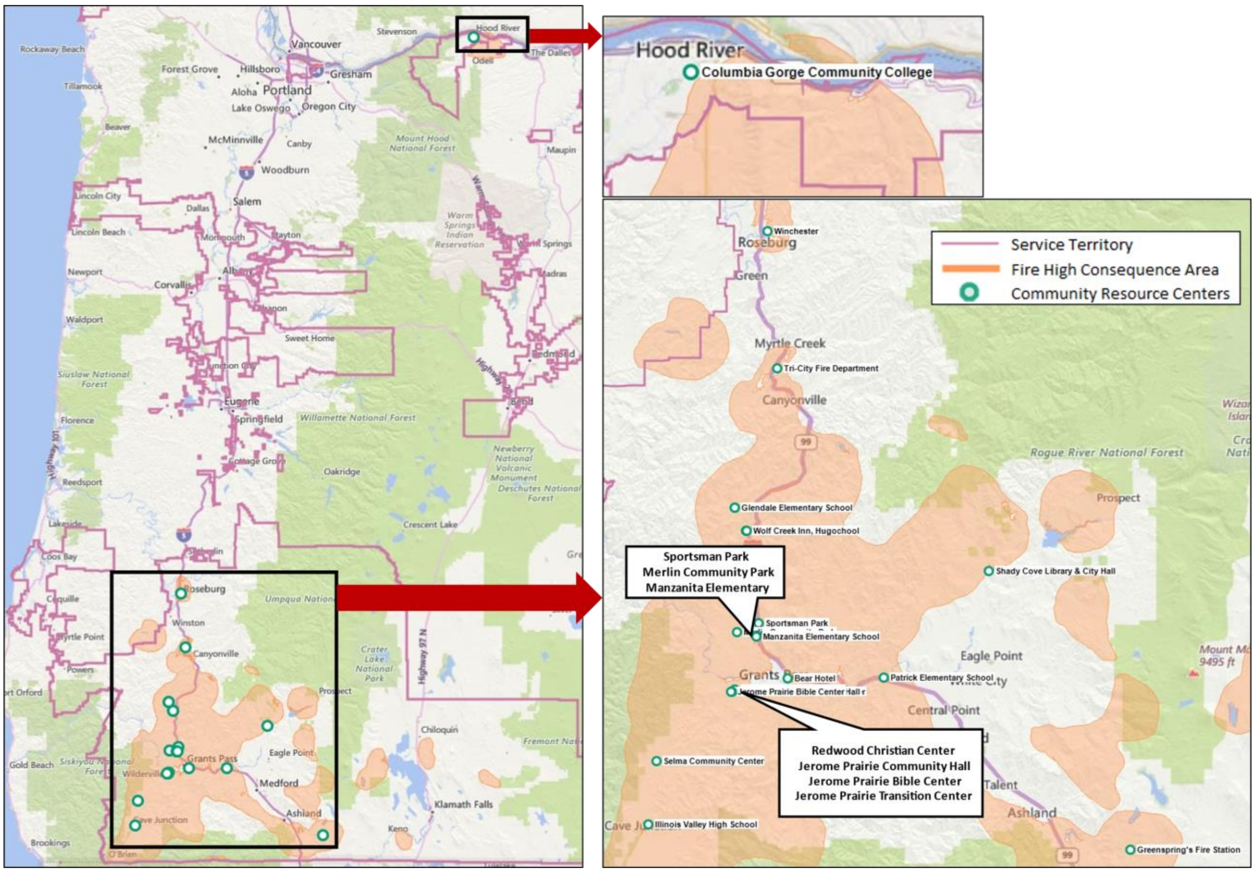


Figure 40: Brick and Mortar CRC Locations in Oregon

Depending on the location of the PSPS and community needs, a CRC could be established in another, not pre-identified facility during the event. Additionally, if an adequate physical facility does not exist, a CRC could be established in a large self-contained tent to provide resources as depicted in Figure 41. Pacific Power intends to continue collaborating with public safety partners to evaluate the existing CRC locations as well as any future sites or needs.

Figure 41: Example Temporary CRC

8.6 RE-ENERGIZATION

As described in Section 8.3 above, local conditions are continually monitored during an event. Based on forecasted risk reduction, Pacific Power may begin staging resources to expedite restoration, Then, when local conditions subside consistent with the forecasted reduction in risk, restoration activities officially begin. The general steps of restoration are depicted below.

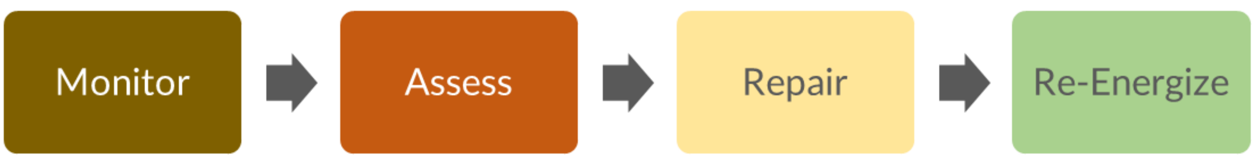


Figure 42: General Re-Energization Process

As indicated above, once the local and forecasted conditions are favorable to reenergize and no new risk(s) have been identified, field personnel begin assessing the deenergized circuits generally through ground or air patrols. Power lines that have been deenergized during a PSPS event have been exposed to strong winds and the potential for damage. In addition, even after the wind has dropped to levels low enough to support a decision to re-energize, fire weather conditions typically remain elevated. Therefore, before reenergizing a line, post-event assessments are completed to determine whether any damage has occurred to the line and/ or substation that needs to be corrected prior to reenergization (e.g., line down, broken crossarms, tree through line, and/ or tree branches or other items blown into the line). Field personnel report any damage identified to Pacific Power's facilities to the ECC where it is tracked. If issues are discovered, the necessary repairs are made within an appropriate corrective time-period.

While all lines and facilities (e.g., substations) deenergized as part of a PSPS event are assessed, a step restoration process is leveraged where possible so that power to customers may be restored as the assessments progresses instead of waiting for the assessment of the entire impacted area to complete prior to re-energization. While not to scale or representative of an actual event, this concept is visually depicted in Figure 43 below.

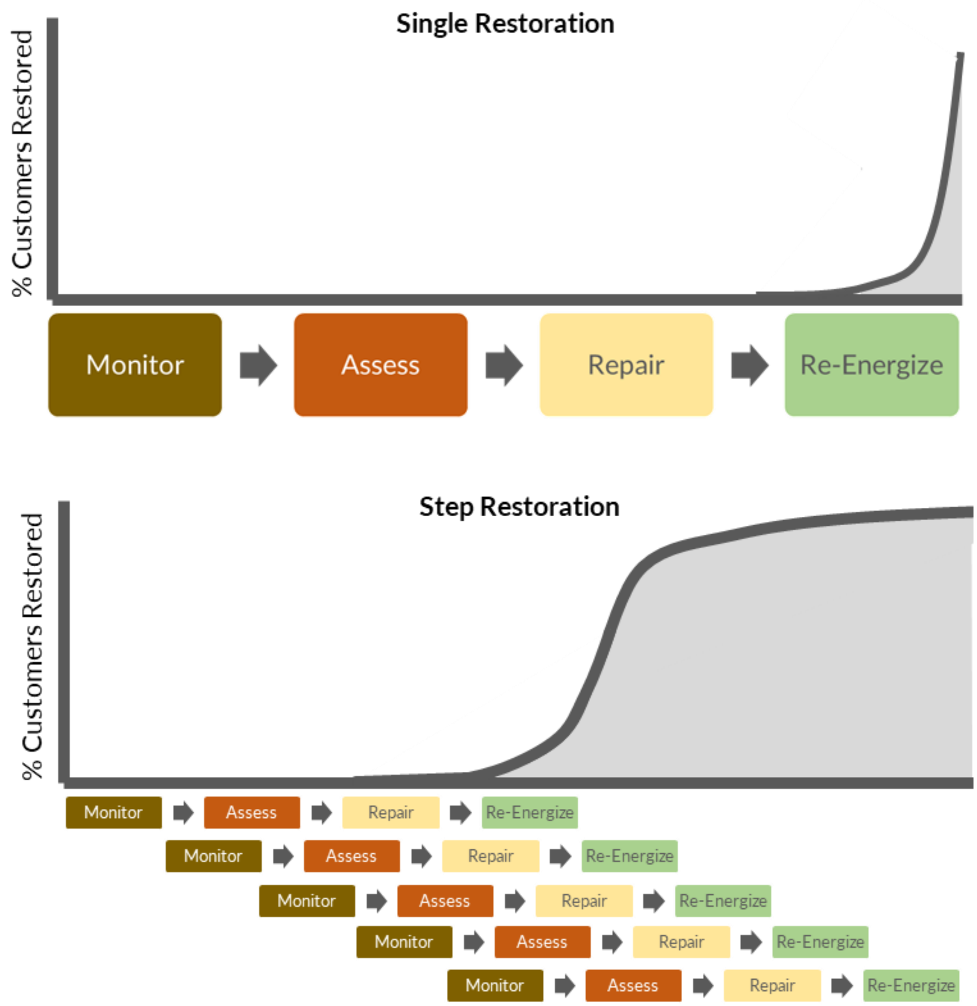


Figure 43: Visual Depiction of Step Restoration

Wherever possible, Pacific Power also works with emergency and public safety partners to identify critical customers for prioritization. After the line patrol and facility inspection is completed, the impacted circuits/ portions of circuits are reenergized and the date and time of reenergization is logged. Once service is restored to all customers impacted by the PSPS event, the event concludes.

8.7 2022 EXPERIENCE

Pacific Power has identified four key opportunities for improvement moving forward based on the experience in 2022:

- **Broaden public outreach and engagement**. While communication cadence to impacted customers occurred as planned, insufficient communication to customers not directly impacted led to some confusion. Pacific Power will expand its communication and overall preparedness as appropriate in an attempt to address gaps.
- **Strategize Community Resource Center (CRC) locations.** Three CRCs were stood up and visited by over 300 customers during the September 2022 PSPS event. However, the majority of customers visited only one CRC in particular. The Company will continue to emphasize CRC panning during workshops and tabletop exercises to work with local public safety partners and better identify community needs during an event.
- **Streamline GIS and information sources.** Due to the dynamic nature of a PSPS event, there was a need to manually update multiple sources of information and GIS layers among various internal platforms. Pacific Power plans to leverage the 2023 public safety partner outreach plan to streamline and better aligning GIS layers and information sources to communicate information quickly.
- **Internal communication and coordination**. The majority of documents, communication protocols and processes worked well, yet there is opportunity to build out new tracking tools, documents and training within the response structure. A novel tracking tool was developed during the event and work has started to look at building out additional situational awareness tools.

Additional information regarding Pacific Power's 2022 experience can be found in Pacific Power's 2022 Annual PSPS Report.

9. Public Safety Partner Coordination Strategy

Pacific Power leverages the multi-pronged approach and strategy generally depicted below in Figure 44 to coordinate with public safety partners regarding wildfire mitigation and PSPS preparedness.

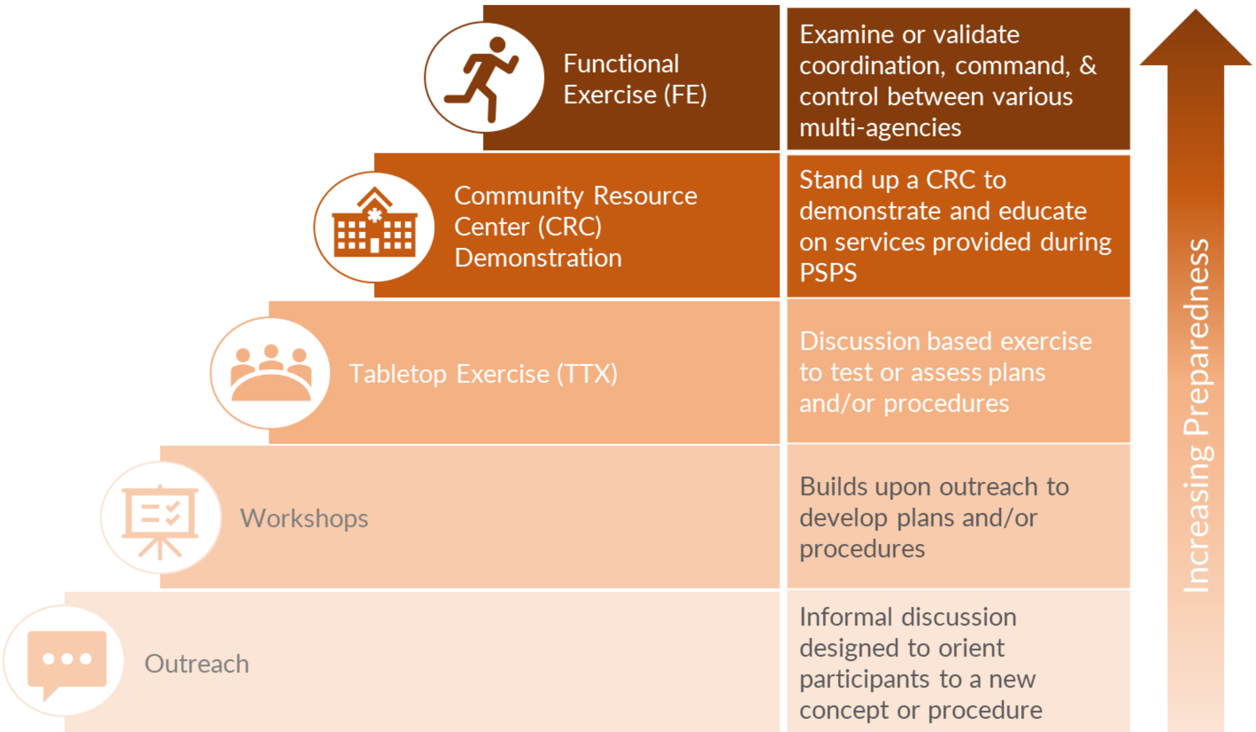


Figure 44: PSPS Preparedness Strategy

As a part of this strategy, each element builds upon the previous step to increase overall preparedness. These elements, which include outreach, workshops, tabletop exercises (TTXs), CRC demonstrations, and functional exercises (FEs) are described in more detail in the following subsections.

9.1 GENERAL OUTREACH

Pacific Power participates in multiple Public Safety Partner meetings and workshops throughout the calendar year across its service territory. Meetings include monthly, quarterly, and annual County and State Emergency Management partner meetings, in addition to pre- and post-fire season collaboration meetings with local, state, and federal fire suppression agencies. This informal discussion is designed to orient participants to a new concept or procedure and continue fostering key working relationships with public safety partners.

Additionally, Pacific Power provides an annually updated webinar, prominently displayed on the Wildfire Safety website, as further described in the Education and Awareness Strategy section, to provide additional information on the PSPS practices.

9.2 WORKSHOPS

Workshops are more local, targeted discussions that build upon general outreach to further compare and refine plans, streamline processes, and confirm capabilities (such as customer outreach, critical facilities and CRC locations and operations) with local public safety partners. As Pacific Power expands its PSPS preparedness in 2023, these workshops will be targeted in locations outside of the FHCA and used to bring new communities and public safety partners up to speed. In 2022 no workshops were conducted as outreach was targeted within the FHCA. In 2023, Pacific Power plans to complete six (6) workshops in new communities outside of the FHCA.

9.3 TABLETOP EXERCISES (TTXS)

Pacific Power facilitates annual discussion based and functional tabletop exercises to develop awareness of PSPS planning and procedures. These exercises aim to facilitate public and private sector coordination, validate communications protocols, and verify capability to support communities during extreme risk events through mitigation actions such as the deployment of community resource centers. Additionally, the exercises include the collective identification of critical infrastructure at the county level to better inform restoration planning and notifications. Pacific Power collects after-action reports from both exercises and real-world events involving wildfire safety and Public Safety Power Shutoff. The after-action reports request feedback on areas for improvement, potential corrective actions and suggestions for plan or procedure development. Suggestions received are considered for inclusion in a comprehensive plan which is shared with the appropriate public safety partners.

9.4 CRC DEMONSTRATIONS

Pacific Power will provide a public demonstration of the Community Resource Center (CRC) prior to the start of wildfire season. This public event planned for April 2023 will provide an opportunity for members of the public, as well as public safety partners, to learn about the type of services offered at a CRC during a PSPS event.

9.5 FUNCTIONAL EXERCISE (FE)

Functional Exercises (FE) are the final step in PSPS preparedness. These exercises are used to examine or validate coordination, command, and control between various multi-agencies. Unlike TTXs or workshops which are discussion based, these exercises are larger scale, last much longer (some can last multiple days), require significantly planning and coordination, and include deployment of resources to practice protocols and processes. A functional exercise requires that part of the plan be physically conducted. Examples relevant to a PSPS FE might include performing customer calls or updating websites. In order to be successful, functional exercises require foundation planning, such as workshops and TTXs, to be completed and formal plans to be in place. Currently, Pacific Power is not planning to conduct a functional exercise in Oregon in 2023. Pacific Power does expect to leverage its experience conducting functional exercises in other states with more mature PSPS programs and incorporate functional exercises in Oregon in the future as needed. .

9.6 2022 ACTIVITIES

Below is a table of engagement sessions and tabletop exercises completed in 2022.

Table 23: 2022 Completed Preparedness and Tabletop Exercises

Date	Host	Target Region / County	Topic
APRIL 14, 2022	Pacific Power	Josephine, Jackson, Lincoln, Hood River/Wasco & Douglas Counties	Tabletop Exercise
APRIL 21, 2022	Deschutes County Emergency Management	Deschutes County	2022 Wildfire Season Planning Session
APRIL 21, 2022	Regional Disaster Preparedness Organization	Clackamas (OR), Columbia (OR), Multnomah (OR), & Washington (OR)	Wildfire Preparedness & Emergency Management Review
MAY 3, 2022	Lincoln County Emergency Management	Lincoln County	Wildfire Tabletop
MAY 5, 2022	Oregon Emergency Management Association	State of Oregon	Emergency Management Program, PSPS Protocols, & 2022 Summer Priorities Review
MAY 6, 2022	Pacific Power	Hood River & Wasco Counties	Tabletop Exercise
MAY 19, 2022	Lincoln County Emergency Management	Lincoln County	Tabletop Exercise

9.7 2023 EMERGENCY PREPAREDNESS AND EXERCISE PLAN

In 2022, Pacific Power's public safety partner coordination strategy was primarily focused on areas and counties located within the FHCA. In 2023, Pacific Power is expanding PSPS preparedness and intends conduct workshops targeting counties located outside of the FHCA. Additionally, instead of conducting multiple small TTXs as was done in 2022, two regional TTXs are planned in 2023 to improve efficiency and enhance broader coordination and collaboration. While these tabletops will still target certain counties, officials from adjacent counties will also be invited to attend to encourage expanded participation. Also new in 2023, Pacific Power will be hosting a CRC demonstration. CRC demonstration plans are under development with an initial location target in Hood River. Table 24 and Figure 45 below summarize the 2023 planned activities.

Table 24: 2023 Emergency Training and Exercise Plan

Planned Activity	General Location[25]	Target Counties[26]	Planned Timeframe
Workshop 1	Southeast OR (Klamath Falls)	Klamath, Lake	March 2023
Workshop 2	Central OR (Bend)	Deschutes, Jefferson, Crook	March 2023
Workshop 3	Willamette Valley (Albany)	Lane, Marion, Linn, Benton, Polk	March 2023
Workshop 4	Eastern OR (Pendleton)	Umatilla, Wallowa, Sherman, Gilliam, Morrow	April 2023

[25] Pacific Power plans to work with public safety partners to select the most appropriate location for these activities. Currently, the locations are depicted as general locations and should be considered estimates.

[26] While the target counties that informed the plan and strategy are listed in the table, Pacific Power may invite public safety partners and officials from adjacent counties as needed.

Planned Activity	General Location[25]	Target Counties[26]	Planned Timeframe
Workshop 5	Southern OR Coast (Coos Bay)	Coos	April 2023
Workshop 6	OR Coast (Astoria)	Lincoln, Clatsop	April 2023
Regional TTX 1	Southern OR (Medford)	Douglas, Jackson, Josephine	April 2023
Regional TTX 2	Northern OR (Hood River)	Hood River, Wasco	April 2023
CRC Demonstration	Northern OR (Hood River)	Hood River, Wasco	April 2023

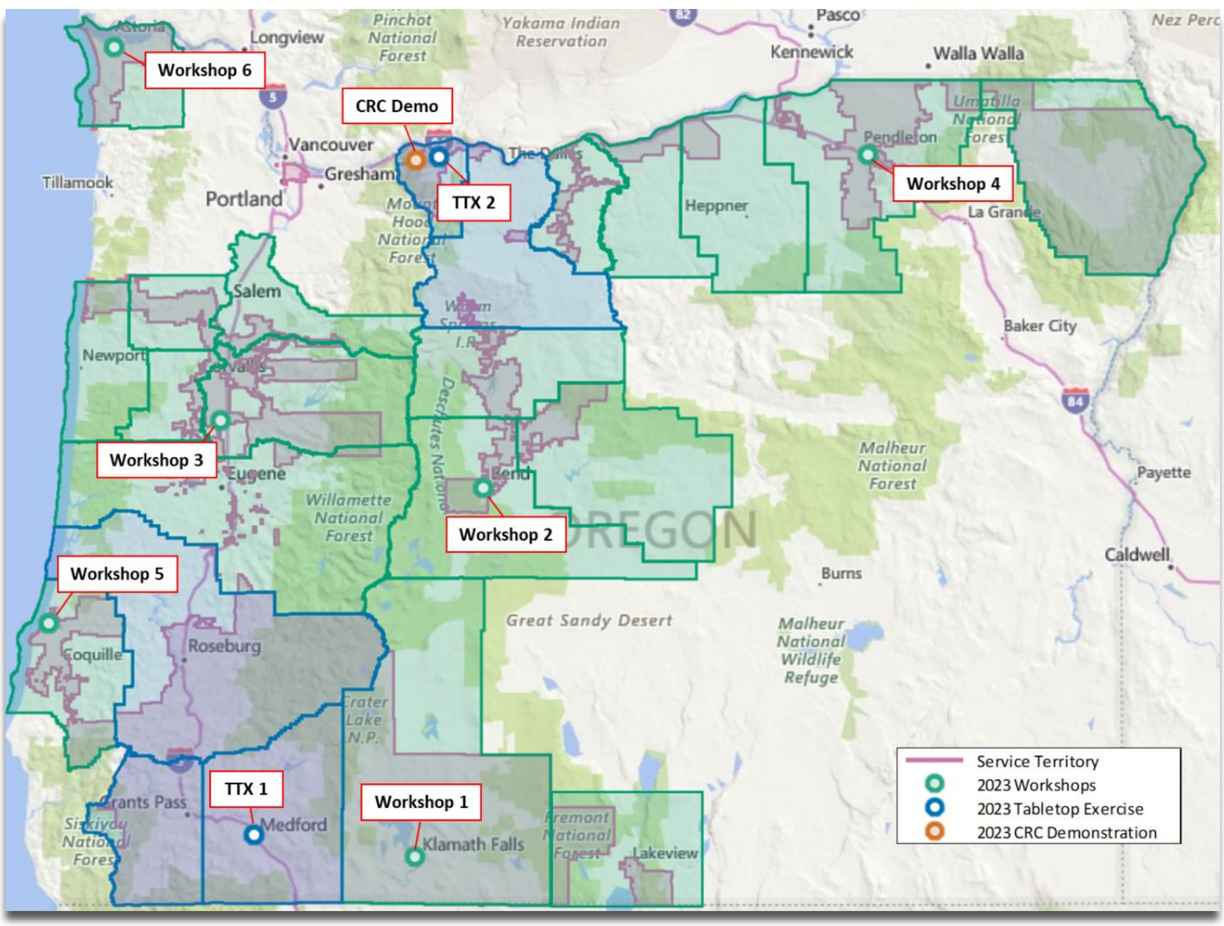


Figure 45: 2023 Emergency Training and Exercise Plan

9.8 PUBLIC SAFETY PARTNER PORTAL

During a PSPS event, Pacific Power recognizes the importance of providing additional geographical details of the affected area. Therefore, in addition to the preparation strategy described above, Pacific Power is currently working to develop a secure, web-based portal consistent with the requirements in OAR 860-300-0060[27] where critical information can be shared with Public Safety Partners[28] during a PSPS event. Once completed, the Public Safety Partner portal will be a secure, map-centric application that will host critical GIS files as well as information regarding critical facilities and infrastructure such as primary/secondary contact information and known backup generation capabilities. In addition to enhancing coordination with local public safety partners, the portal will also enhance Pacific Power's capabilities to evaluate, communicate with, and prioritize restoration of critical facilities that provide essential services for public safety. This project was initiated in 2022 and will complete in 2023 as depicted in the figure below.

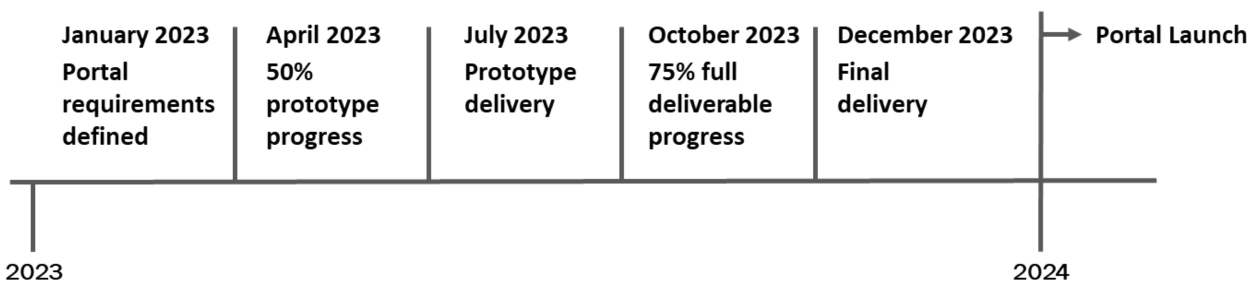


Figure 46: Public Safety Partner Portal Project Timeline

[27] OAR 360-300-0060 requires that Public Utilities create a web-based portal for use during PSPS events by March 31, 2024.

[28] Public safety partners generally include emergency responders from federal, state, local and tribal governments, telecommunication providers, water agencies, public-owned utilities, emergency hospitals, and transportation agencies

10. Wildfire Safety & Preparedness Engagement Strategy

Pacific Power employs a multifaceted approach to support community engagement and outreach with the goal of providing clear, actionable and timely information to customers, community stakeholders and regulators. Over the past several years, the company has engaged customers and the general public throughout its three-state service area on wildfire safety and preparedness through a variety of tactics including webinars, in-person forums, targeted paid advertising campaigns, informational videos featuring company subject matter experts, press engagement, distributed print materials, infographics, social media updates, and communication through bill messages, emails and website content, among other communication channels. The wildfire safety and preparedness community engagement plan continues to evolve year-over-year as customer and stakeholder feedback and regulatory guidance is incorporated. Pacific Power maintains an awareness and engagement strategy that is flexible and allows for dynamic tactics, informed by customer survey data, community stakeholder input and community needs. Overall, Pacific Power's plan includes information that can be heard, watched and read in a variety of ways with the goal of accessibility and understandability.

10.1 AWARENESS AND ENGAGEMENT CAMPAIGN

For the past several years, the company has deployed some form of paid media campaign to raise awareness and action on wildfire safety and preparedness. The 2022 wildfire safety and awareness paid advertising campaign, which launched May 30 and concluded October 2, included radio spots, digital over-the-top (OTT) pre-roll video ads (Hulu, Pluto TV, Roku, etc.), digital audio ads (Spotify, Pandora, etc.) display ads (search and web banners), and social media static and video ads (Facebook, Instagram and YouTube) – each delivered in English and Spanish.

Metropolitan Statistical Areas in Oregon targeted through the paid campaign included Bend-Prineville, Medford-Grants Pass, Eugene-Springfield and East Portland Metro-Salem. Smaller markets included Hood River, Roseburg, Klamath Falls, Astoria and Albany-Lebanon.

Generally, the campaign focused on two main topics: personal preparedness and safety, and investments the company is making to reduce wildfire risk. The call-to-action in each campaign vertical compelled the audience to visit Pacific Power's wildfire safety and preparedness online resources. In 2022, the various ads across multiple channels collectively received nearly 13,000,000 impressions and just over 34,500 clicks to company-hosted wildfire safety and preparedness informational webpages. Engaging with local and regional news media outlets is another important component of the awareness and engagement campaign. Each year prior to fire season, Pacific Power distributes updated wildfire safety information and information on the company's WMP to press outlets across its service area as an additional low-cost outreach method. During the 2022 wildfire season, company wildfire safety and mitigation subject matter experts provided interviews to nearly twenty news outlets which resulted in sustained coverage of the company's WMP in key markets including Portland, Bend, Medford, Astoria, Roseburg and statewide outlets such as Oregon Public Broadcasting and *The Oregonian*. Additionally, during the September Public Safety Power Shutoffs the Pacific Power Public Information Officer provided nearly 50 media interviews. In addition to event-specific information, many of these interviews also delved into year-round wildfire mitigation strategies executed by the company and outage preparedness and general wildfire safety information.

In addition to paid and earned (news media engagement) awareness and engagement strategies, Pacific Power also communicates to customers about wildfire safety and preparedness through channels it owns or manages. Bill messages, website and social media updates, emails, texts, automated phone calls are all an additional low cost means to reach customers.

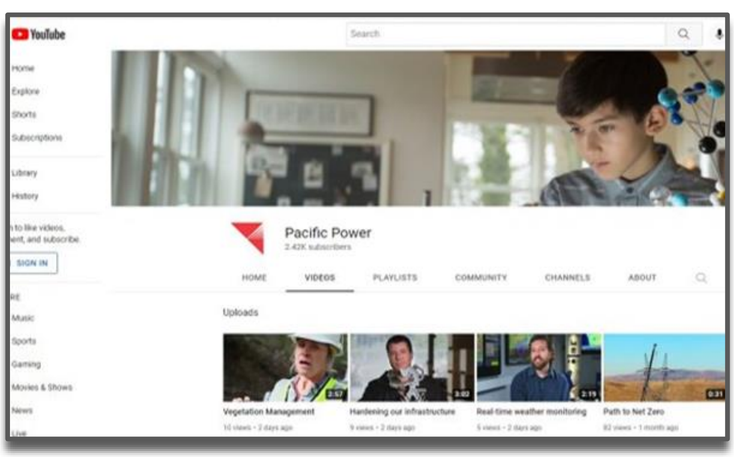


Figure 47: Sample YouTube Material

10.2 SUPPORT COLLATERAL

Pacific Power has developed a number of print and digital wildfire safety and preparedness collateral pieces including factsheets, flyers, brochures, infographics and safety checklists. These items are accessible through the company wildfire safety webpages and are utilized at public meetings and community events to describe PSPS (including its necessity, PSPS considerations and expectations before, during and after a PSPS) and to provide general information on emergency kits/plans and preparation checklists, among other topics. Same material can be seen in Figure 48. Annually, the Pacific Power communications team updates these materials to ensure the information is relevant, accessible and actionable. Spanish versions of each piece of collateral are also available.

Figure 48: Sample Support Collateral

10.3 CUSTOMER SERVICE TRAINING

Pacific Power has established a process to track customer calls regarding wildfire safety, wildfire preparedness and other wildfire concerns. This process will allow the customer care specialist to select the term 'wildfire' from a drop-down menu at the conclusion of the call. Reports generated will be generated on a quarterly basis for review beginning in January of 2023 and will be used to better understand customer concerns and overall call volume related to wildfire.

Customers with specific language needs can contact the company's customer care number and request to speak with an agent that speaks their preferred language. Pacific Power employs Spanish-speaking customer care professionals and contracts with a 24/7 service that provides interpretation in real-time over the phone in hundreds of languages and dialects.

Customer care agents have received training on wildfire safety and preparedness and PSPS-related information to facilitate a conversation between the customer and interpretive service to ensure the customer receives the wildfire safety and preparedness or PSPS-related information they seek.

10.4 WILDFIRE SAFETY, PREPAREDNESS AND PSPS WEBPAGES

The Pacific Power website provides robust and comprehensive information on company wildfire mitigation programs, general wildfire safety, PSPS information and more. In 2022, the company launched updated wildfire safety webpages to improve customer experience and allow for improved accessibility to wildfire-related information. The page refreshes include a new infographic depicted in Figure 49 that demonstrates the work in progress to improve the safety and reliability of the grid along with embedded videos highlighting the work Pacific Power will complete to improve the system, increase situational awareness and prepare for events that may result in outage activity. The wildfire safety webpages were also updated in early 2022 to include a 1-to-1 translated Spanish wildfire safety pages. This includes a frequently asked questions section, links to public safety power shutoff maps and information, and resources including public safety power shutoff and wildfire preparedness brochures.

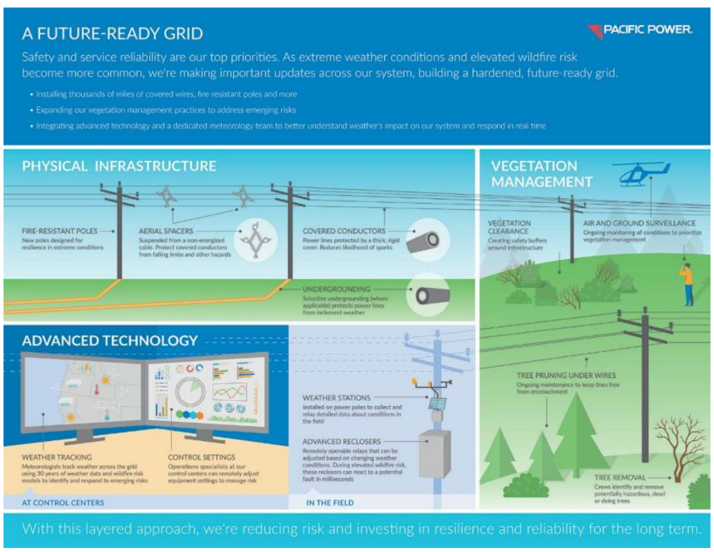


Figure 49: New Wildfire Safety Infographic

Various resources and tools for community preparedness can be found on the Pacific Power wildfire mitigation webpage (www.pacificpower.net/wildfiresafety). Prompts for customers to update contact information are displayed prominently on the page. Guides and checklists for creating an emergency plan/outage kit are easily accessible. The Wildfire Safety webpages include a link to annual WMP for review, and links to webinars and videos describing key components of the plan for watching, providing site visitors a variety of ways to consume and engage with wildfire safety and preparedness information.

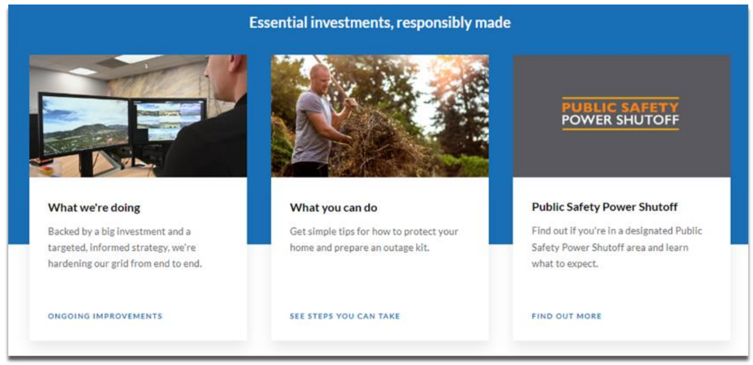


Figure 50: Sample Website Material

The Pacific Power Public Safety Power Shutoff webpage (www.pacificpower.net/psps) provides educational material on PSPS. The webpage describes why a PSPS would happen, includes details of the wildfire risks monitored prior to executing a PSPS, and how customers can prepare for PSPS. Information on how customers will be notified, what to expect during an event and the service restoration process if a PSPS is deemed necessary is detailed on the webpage. Pacific Power seeks to serve the community by providing general situational awareness information, such as an interactive map of the PSPS areas shown in Figure 51 and a seven-day forecasting table that provides insight into if the company is considering a PSPS and which areas might be affected.

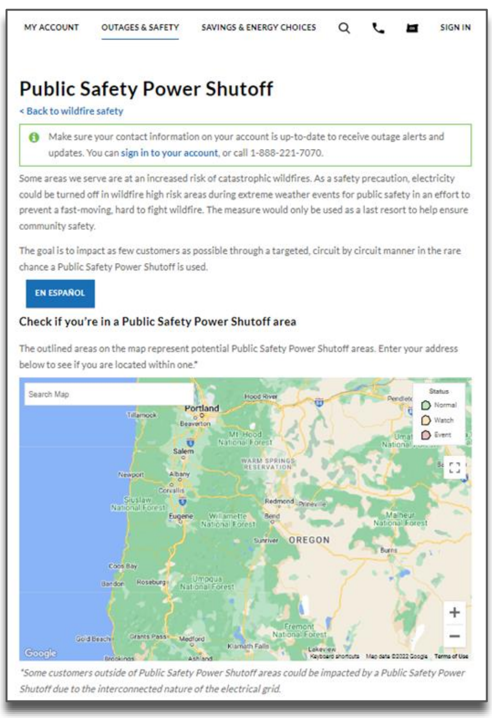


Figure 51: PSPS Interactive Map

To ensure that the website information is provided in identified prevalent languages, the PSPS webpage has a message in nine languages – which includes Chinese traditional, Chinese simplified, Tagalog, Vietnamese, Mixteco, Zapoteco, Hmong, German and Spanish that states "A customer care agent can speak with you about wildfire safety and preparedness. Please call 888-221-7070." The company will continue to work with Public Safety Partners and Community-Based Organizations to determine if additional languages should be included.

10.5 WEBINARS AND COMMUNITY FORUMS

Once a year, Pacific Power hosts a webinar providing an overview of the company's wildfire mitigation program and strategies. Among other items, key mitigation strategies addressed in the webinar include situational awareness capabilities, system hardening investments, and PSPS process review. The webinar also brings to focus how Pacific Power engages with local communities and Public Safety Partners on wildfire safety. The webinar also serves as a forum for customers, community stakeholders and the public-at-large to ask questions during the live stream. A webinar for Oregon customers was delivered June 13, 2022. The webinar along with a video titled "Investing in Resilience – Wildfire Safety" were posted on the Pacific Power website and YouTube channel.

Pacific Power is a public utility, and as such, aims to develop a WMP that aligns with public interests. In 2022, the company conducted a series of in-person and virtual public engagement forums designed to communicate an overview of its 2022/2023 WMPs, provide an environment for direct questions and answers, and foster public engagement in the company's overall wildfire mitigation planning processes. Four (4) in-person community engagement forums were hosted in FHCA with an additional forum hosted virtually to broaden the scope of engagement and awareness of the company's WMP. The following table describes these forums and overall attendance.

Figure 52: Meteorology Presenting at the WMP Forum

Table 25: Forum Details and Attendance

Community	Date	Address	Total Attendees (In Person + Virtual)	In Person or Virtual
CENTRAL POINT, OREGON	October 18, 2022	1 Peninger Road, Central Point, OR	16	In-person w/ Virtual Option
CANYONVILLE, OREGON	October 19, 2022	146 Chief Miwaleta Lane Canyonville, OR	12	In-person w/ Virtual Option
GRANTS PASS, OREGON	October 19, 2022	1451 Fairgrounds Road Grants Pass, OR	22	In-person w/ Virtual Option
MOSIER, OREGON	October 20, 2022	1000 4th Avenue Mosier, OR	5	In-person w/ Virtual Option
VIRTUAL	December 1, 2022	Virtual	-	Virtual Only

Public forums included presentations from company representatives on strategic wildfire mitigation programs, system hardening and improvements, PSPS protocols, and customer engagement and preparedness. For those unable to travel to the meetings, forum sessions were streamed live online and included Spanish and American Sign Language interpretive services. Electronic Spanish interpretive headsets were available to in-person attendees. The community forums were promoted through paid advertising, local news coverage, and published to the Pacific Power website and social media channels -- with links provided for live stream access. Local elected officials, emergency managers and other stakeholders were invited via email.

During these forums, communities were informed on key elements of the Pacific Power WMP and question and answer sessions (both in-person and online through a chat function) were conducted to allow for community member engagement. The forums allowed for a two-way dialogue and created space for feedback to be collected and applied in context to key elements of the plan. Additionally, participants were provided with a means of submitting follow up questions via email. Informational brochures were also available to community members and feedback received was captured for further consideration and discussion. The following table describes the general feedback and dialogue from each forum.

Table 26: Feedback from Forums

Event	Feedback Overview
CENTRAL POINT, OREGON	Pacific Power provided feedback and responses to 12 inquiries regarding PSPS policies and procedures; vegetation management practice; AFN customer protections; information access and costs associated with implementation of its WMP.
CANYONVILLE, OREGON	Pacific Power provided feedback responses to eight inquiries regarding PSPS policies and procedures, vegetation management practices; and costs associated with implementation of its WMP. Community members inquired about the future of underground facilities. Online inquiries were made regarding AFN customers, hospitals and care facilities that may be adversely affected by a PSPS.
GRANTS PASS, OREGON	Pacific Power provided feedback and responses to 17 inquiries regarding PSPS policies and procedures and the situational awareness and outage notification systems. Several comments focused on the statewide efforts to support wildfire mitigation planning. Community members also inquired about the future of underground facilities.
MOSIER, OREGON	Pacific Power provided feedback and responses to 11 inquiries and comments regarding PSPS policies and procedures; its relationships with local emergency management; and inquiries regarding the future of underground facilities.
VIRTUAL	No questions / requests

10.6 CAMPAIGN AND ENGAGEMENT EVALUATION

Pacific Power contracted with a third-party research group to conduct a survey of customers in its Oregon service territory. The overall objective of this research was to measure the public's awareness of messaging related to wildfire preparedness and safety. Specific research objectives included:

- Measure awareness of Pacific Power messages related to wildfire preparedness
- Identify recall of specific message topics
- Identify recall of message channels
- Measure recall and understanding of Public Safety Power Shutoff or PSPS
- Evaluate sources customers are most likely to turn to for information about PSPS
- Evaluate PSPS experience
- Explore actions taken by customers to prepare for wildfire season
- Measure awareness of Pacific Power's efforts to reduce the risk of wildfires
- Evaluate PSPS notification perception

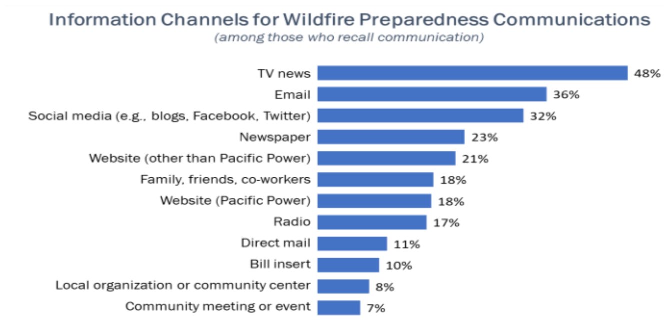
The target audience for the survey included residential, business and critical customers in Oregon. The study was conducted using a mix of online (2,860 completed) and phone (75 completed) surveys. Surveys were available to customers in English and Spanish. A total of 2,935 surveys, including 75 from critical customers, were completed between October 3 and October 16, 2022.

Additionally, six in-depth interviews were conducted with community-based organizations (CBOs) throughout Oregon. CBO interviews lasted 30 minutes and were conducted using Microsoft Teams; participants were paid $100 as a "thank you" for their time and feedback; and interviews were scheduled using a "warm handoff" from Pacific Power.

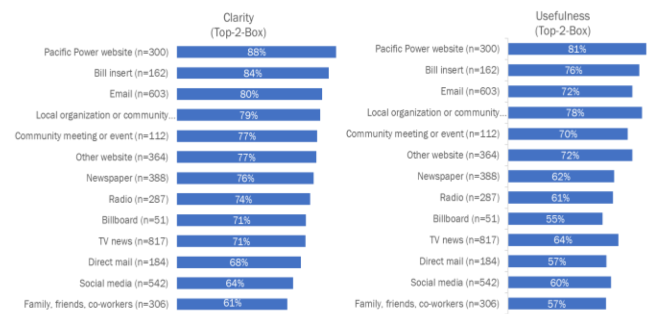
High level findings from the customer and CBO surveys are included below and grouped based on general awareness, PSPS awareness, and PSPS experience.

General Wildfire Safety and Preparedness Messaging Highlights

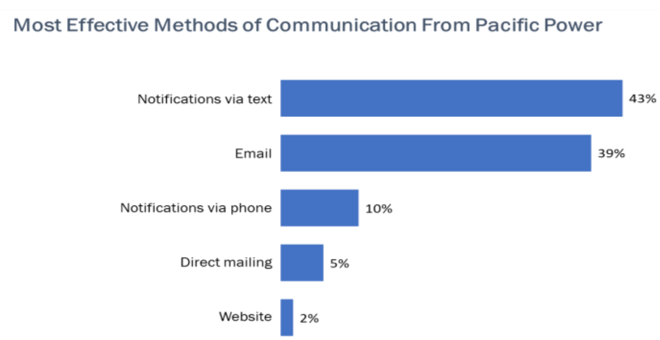
TV News, email and social media were the primary channels recalled for general wildfire preparedness communications.



Of the messages recalled **Pacific Power's website was considered the most clear and useful source** for information about wildfire preparedness.

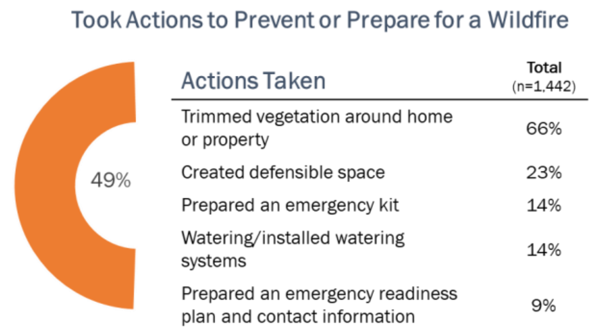


Notifications via text message were considered the most effective communication method **from Pacific Power**, followed closely by email.

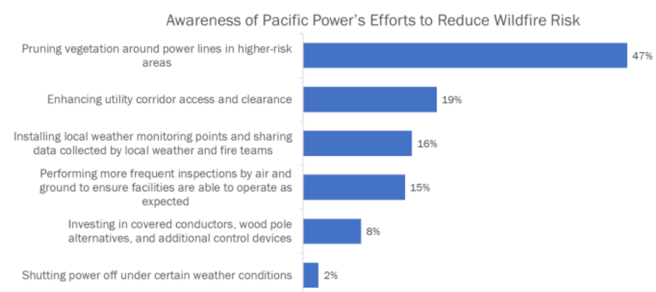


Regarding content of messages recalled, **59% of respondents were aware of personal preparedness.**

49% of respondents also reported taking action to prevent wildfires or to prepare their home or business for the event of a wildfire.

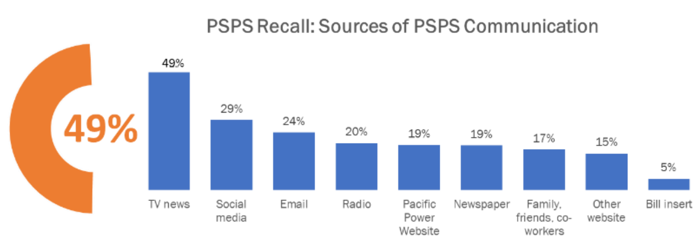


In terms of Pacific Power's efforts to reduce wildfire risk, respondents were **most aware (47%) of pruning vegetation** around power lines in higher-risk areas.

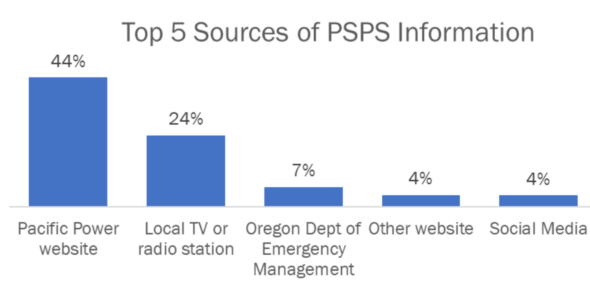


PSPS Messaging and Awareness

49% recalled seeing, hearing or reading the phrase "Public Safety Power Shutoff or PSPS" primarily from TV news, social media, email, and radio.



The Pacific Power website was reported as the **main source of PSPS related information.**



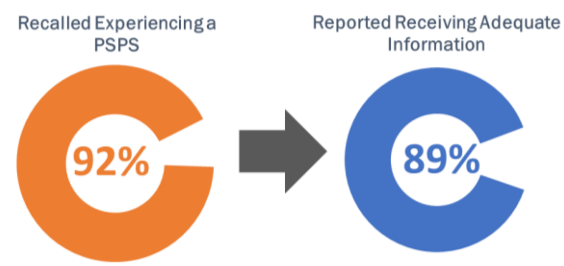
80% reported understanding that "for areas at a higher risk of fast-spreading catastrophic wildfires, **the utility will proactively shut off power during extreme and dangerous weather."**

PSPS Understanding	October 2022 (n=1,443)
For areas at a higher risk of fast-spreading catastrophic wildfires, the utility will proactively shut off power during extreme and dangerous weather.	80%
Before considering a Public Safety Power Shutoff the utility assesses several factors: dry trees and other fuel, winds, extremely low humidity, weather conditions, population density, real-time on-the-ground observations and input from local public safety and health agencies.	60%
A Public Safety Power Shutoff is a last resort by the utility in an effort to prevent a fast-moving, hard to fight wildfire to help ensure customer and community safety.	51%
The likelihood of a Public Safety Power Shutoff is reduced when the utility takes steps to harden the electric grid.	28%
Taking steps to enhance situational awareness by tracking satellite information and monitoring weather conditions can reduce the likelihood of a Public Safety Power Shutoff.	25%

40% of respondents reporting awareness of **ability to update contact information; 58%** of which have **updated contact information**

2022 PSPS Experience

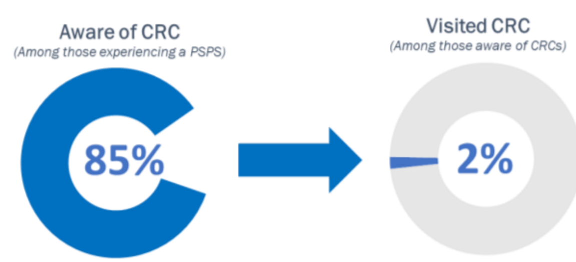
Among customers who experienced a PSPS, **92% recalled the event** and **89% reporting receiving adequate information.**



General recommendations focused on **increasing preparation time** and clearer communication regarding **restoration planning.**

Recommendations for Improvement	
Timing/more time to prepare	15%
Better communication	12%
Updates on outage duration	6%

Among customers who experienced a PSPS, **85% reported awareness** of CRCs**, 2%** of those **reported visiting** a CRC



Just under six in ten **(56%) agreed** that notifications should be sent if there is **any possibility of a PSPS**, and another **35% say** notifications should be sent only if there is a **high likelihood.**

PSPS Notifications Perception	October 2022
Notifications should be sent if there is any possibility of a PSPS	56%
Notifications should only be sent if there is a high likelihood of a PSPS	35%
Notifications should only be sent if a PSPS is certain to occur	9%

"False Alarms" Impact

"It created unnecessary stress abou impending loss of electricity."

"I was not affected."

Additionally, based on the survey results, English is not a primary language for one in ten customers (10%), but is still preferred for communications for the vast majority (99%).

- Out of all respondents, 2% responded that it would be helpful for them or anybody else in their household to receive communication in another language.
- When asked what their preferred language would be to receive communications from Pacific Power, Spanish (<1% of all respondents), Simplified Chinese (<1%), Traditional Chinese (<1%), Russian (<1%), Vietnamese (<1%), and Mixteco (<1%) are the only non-English languages mentioned

These highlights are summarized in Table 27 below:

Table 27: Customer Survey Highlights

Topic Area	Recall Rate
Aware of Wildfire Safety Communications	58%
Aware of Communications from Pacific Power (among those aware)	26%
Took Action to Prevent or Prepare for a Wildfire	49%
Recall PSPS	49%
Would Turn to Pacific Power Website for PSPS Info	44%
Aware of Ability to Update Contact Info for PSPS	39%
Know if Address is in PSPS Area	19%
Satisfied with Availability of Resources in Community for Wildfire Safety Info	25%
Aware of Additional PSPS Notices for Those with Medical Need (among those with medical need)	12%

Recommendations

Based on the survey results, the third-party survey administrator suggested the following considerations for the 2023 Wildfire Safety and Preparedness customer engagement campaign:

- Prioritize TV news, email, and social media to educate customers.
- Because the Pacific Power website, bill inserts, and emails are considered highly clear and useful, focus broader media communications on driving customers to the website and leverage bill inserts to both refer customers to the website and quickly communicate highly important information.
- Local organizations and CBOs are perceived to provide clear and useful information and can provide an opportunity to reach vulnerable or difficult to target customers.
- Text messages are considered highly effective methods of communication. Consider limiting the use of text messages to only critical communications to maintain perceptions of urgency.
- Focus communications on PSPS / outage preparedness (including an emergency kit and readiness plan), and the steps Pacific Power is taking.
    - Action for steps beyond creating a defensible space is lagging.
    - Awareness of Pacific Power's efforts to prune vegetation is high, but other steps taken have much lower awareness. Evaluate whether the messaging approach around pruning can be applied to other readiness activities.
    - Awareness of PSPS is high in the Willamette Valley North region, which was recently affected by PSPS, but lags in other areas of the state. Efforts should focus on Southern and Northeast Oregon, which have lower than average awareness of PSPS.
- Heating/cooling and food replacement are the top concerns during an extended outage. Ensure these needs are covered in any communications about preparation for PSPS events.

10.7 2023 WILDFIRE COMMUNICATIONS AND OUTREACH PLAN

The 2023 Wildfire Communications and Customer Engagement plan will look similar to what the Company deployed in 2022. However, based on customer survey feedback, changes to messaging and content to promote broad PSPS awareness and steps the company is undertaking to clear vegetation around assets will be prioritized. Company communications staff will continue to refine supporting content for customer ease of use and access. The picture below outlines next year's plan.

Figure 53: 2023 Wildfire Communications and Outreach Plan Timeline

10.8 PORTABLE BATTERY REBATE PROGRAM

As discussed in Section 6 and Section 8, certain wildfire mitigation strategies can have a negative impact to customer reliability and result in additional outages. While the outreach and engagement strategy described in the sections above aims to inform and enhance customer preparedness overall, Pacific Power is also planning to introduce a new customer program in 2023 to support preparedness. To mitigate the impacts that wildfire mitigation strategies can potentially have on medical baseline customers, Pacific Power plans to implement a new program in 2023 and begin offering rebates on qualifying purchases of portable, backup batteries to medically registered customers in Oregon.

While the program is in the early stages of development, Pacific Power generally plans to offer this rebate in phases through direct outreach to customers throughout Oregon beginning in 2023. Outreach will be first prioritized in the FHCA areas and then broadened across the state. Pacific Power's goal is to increase customer access to resources during service interruptions and mitigate potential impacts to customers who depend on medical equipment powered by electricity.

11. Industry Collaboration

Industry collaboration is another component of Pacific Power's WMP. Through active participation in workshops, international and national forums, consortiums, and advisory boards, Pacific Power maintains an understanding of existing best practices and collaborates with industry experts regarding new technologies and research.

For example, Pacific Power is an active member of the International Wildfire Risk Mitigation Consortium (IWRMC),[29] an industry-sponsored collaborative designed to facilitate the sharing of wildfire risk mitigation insights and discovery of innovative and unique utility wildfire practices from across the globe. This consortium, with working groups focused in the areas of asset management, operations and protocols, risk management, and vegetation management, facilitates a system of working and networking channels between members of the global utility community to support the ongoing sharing of data, information, technology, and practices.

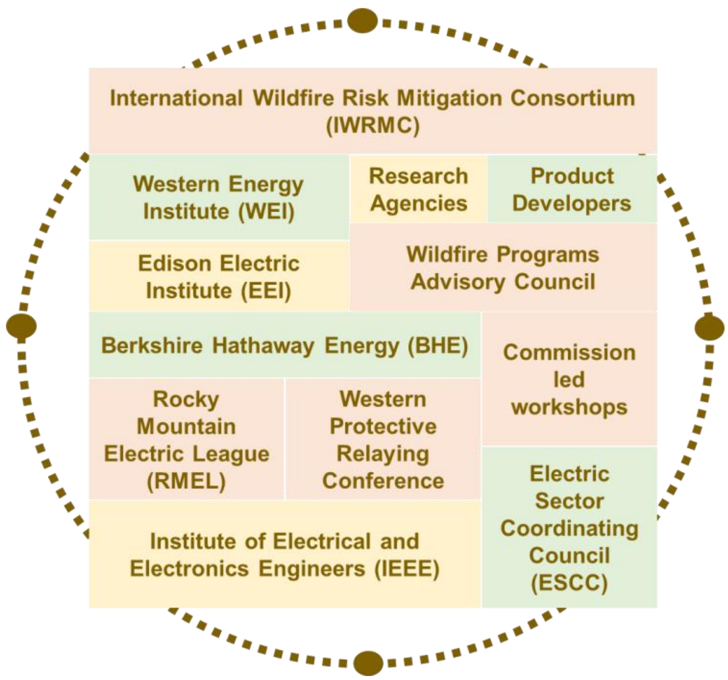


Figure 54: Key Industry Collaboration Channels

Additionally, Pacific Power plays leadership and support roles through other organizations such as the Edison Electric Institute (EEI), the Electric Sector Coordinating Council (ESCC), and the Institute of Electrical and Electronics Engineers (IEEE). Within the western United States, Pacific Power also engages with the Western Energy Institute (WEI) and the Rocky Mountain

[29] See https://www.umsgroup.com/what-we-do/learning-consortia/iwrmc/

Electric League (RMEL) as well as the Western Protective Relaying Conference. Collaboration also occurs regarding research and applications of technologies through Pacific Power's parent company (Berkshire Hathaway Energy, BHE) and its affiliated companies.

Furthermore, Pacific Power partners with certain research and response agencies to develop and test new technologies, such as existing efforts with the with the Oregon Department of Forestry to install wildfire cameras on utility infrastructure in key, high risk locations. Additionally, Pacific Power is currently working with Texas A&M university to pilot the use of Distributed Fault Anticipation (DFA) technology on its system in Oregon. As part of a multi-year, collaborative effort, Pacific Power plans to install these unique, protection and control devices on its system and test the capability for advanced fault detection and as a potential wildfire mitigation tactic.

Through these various engagement channels, Pacific Power aims to maintain industry networks, understand the evolution of technologies, discover broader applications for such advancements, freely share data to enable scientists and academics, collaborate with developers to push the boundaries of existing capabilities, and expand its research network through support of advisory boards or grant funding. Participation in these industry networks is continuing to increase Pacific Power's confidence in its WMP strategies and program elements.

12. Plan Monitoring & Implementation

In 2022 Pacific Power developed a new department, commonly referred to as Wildfire Safety. This new department consists of thirteen full-time employees, is led by a Managing Director, and includes both a project management office, focused on delivery of line rebuilds and system hardening, and a program delivery team, responsible for overall plan development, monitoring, and implementation. The overall organization is depicted below.

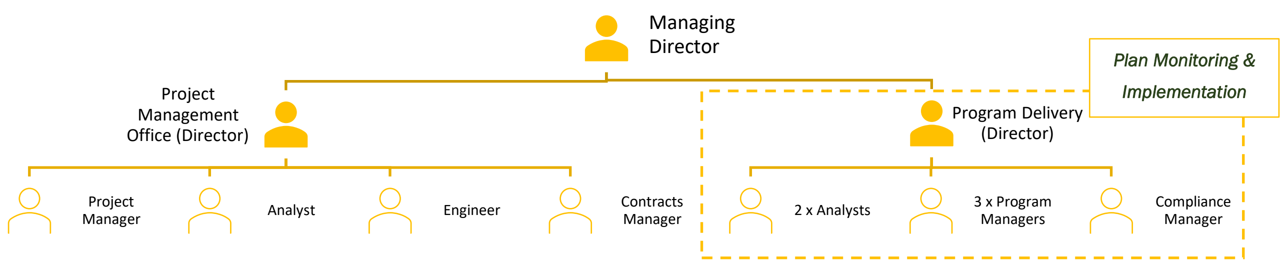


Figure 55: Pacific Power's Wildfire Safety Department

While the broader Wildfire Safety team is tasked with supporting all types of wildfire mitigation initiatives and strategies across the company's entire service territory, a key function of Wildfire Safety Program Delivery team is to develop, implement, monitor, and improve the company's WMP in Oregon. It is the responsibility of Wildfire Safety Program Delivery to coordinate with other internal departments such as Asset Management, Vegetation Management, Field Operations, and Emergency Management to ensure all aspects of the plan are delivered. Additionally, Wildfire Safety regularly evaluates its plan and provides updates as needed and consistent with statutory and regulatory requirements.

In addition to evaluating the plan elements, Pacific Power is also monitoring potential cost sharing and partnership opportunities to secure federal and state grant funding and offset the potential impacts to customers. Many of Pacific Power's wildfire mitigation programs, such as grid hardening which includes investment in transformational technology, align with the goals and objectives of potential grant funds. Beginning in 2022 and continuing into 2023, Pacific Power intends to pursue funding opportunities where appropriate.

13. Plan Summary, Costs, & Benefits

2022 Program Achievements and 2023 Objectives

Pacific Power WMP is designed to provide timely and cost-effective wildfire mitigation benefits through a range of programs. While described in more detail through the plan itself, the table below summarizes the program elements, 2022 achievements, and 2023 program objectives.

Figure 56: Summary of 2022 Program Results and 2023 Objectives[30]

Program Category	General Program Description	2022 Achievements	2023 Program Objectives
Risk Modeling & Drivers	Maintain baseline risk maps and framework to identify areas that are subject to a heightened risk of wildfire and inform longer term, multi-year investment and programs	✓ Maintained FHCA maps & risk assessment ✓ Tracked ignition data for compliance ✓ Initial procurement of new risk modeling tools, datasets, and software	➢ Refresh the FHCA Map ➢ Utilize WRRM to model utility asset fire risk ➢ Implement advanced data analytics tool for RSE modeling, fire incident tracking, and effectiveness evaluation
Inspection & Correction	Continue FHCA inspection programs (5-yr detail, annual visual assurance), accelerated correction timeframes for fire threat conditions (6 months or less), and implementation of IR inspections on transmission	✓ 3,953 incremental detailed inspections ✓ 55,139 incremental visual assurance inspections ✓ 1,308 fire threat conditions corrected ✓ IR Inspection completed on 1,082 miles	➢ Continuation of FHCA Inspection Programs ➢ Expand IR inspection program beyond the FHCA to include approximately 990 additional line miles in 2023

[30] 2022 achievements in this table are estimates or end of year forecasts based on document preparation ahead of the filing.

Program Category	General Program Description	2022 Achievements	2023 Program Objectives
Vegetation Management	Transition to a 3-yr trim cycle system wide, increase post trim clearances in the FHCA, implement annual pole clearing of subject poles in the FHCA, and perform annual inspections in the FHCA	✓ Inspected over 1,700 additional line-miles ✓ Trimmed over 18,600 additional trees ✓ Removed over 22,700 additional trees (including brush equivalent) ✓ Radially cleared over 20,000 poles	➢ Continue implementation of 3-yr distribution cycle ➢ Continue FHCA Vegetation Management programs including expanded post work clearances ➢ Finalize a long-term contract to stabilize resources
System Hardening	Long term investment to mitigate wildfire risk including line rebuilds, system protection and control equipment upgrades, and replacement of OH fuses and adjacent equipment	✓ 2 miles constructed ✓ 91 miles designed ✓ 62 devices upgraded ✓ 1,000 fuses replaced ✓ 2,156 fault indicators installed	➢ Construct 89 miles of covered conductor ➢ Design 125 miles of CC ➢ Upgrade 65 devices ➢ Replace ~10,000 fuses
Situational Awareness	Install and operate a company owned weather station network, implement a risk forecasting and impact-based fire weather model, and inform key decision making and protocols	✓ 86 weather stations installed ✓ Procured WFA-E software ✓ Created public weather website ✓ District Fire Index Daily Process	➢ Install 47 additional weather stations ➢ Fully implement WFA-E ➢ Implement FPI ➢ Complete 30-yr WRF reanalysis ➢ Improve the public weather website
System Operations	Risk-based implementation of EFR settings and re-energization practices in a manner that balances risk mitigation with potential impacts to customers	✓ Risk-based implementation of EFR settings and re-energization practices	➢ Continued risk-based implementation of EFR settings and re-energization practices
Field Operations & Work Practices	Acquire and maintain key equipment (water trucks, COWs, & personal suppression equipment) and implement risk-based work practices and resource adjustments	✓ Risk based work practices ✓ Additional local assessments to inform situational awareness ✓ Acquired 3 water trailers	➢ Purchase 3 COW devices ➢ Continued implementation of risk-based work practices ➢ Assess additional equipment needs

Program Category	General Program Description	2022 Achievements	2023 Program Objectives
PSPS Program	Maintain the ability to actively monitor conditions, assess risk, and implement a PSPS as a measure of last resort in a manner that limits the impacts to customers and communities consistent with regulatory requirements	✓ Implemented a PSPS event ✓ Deployed 3 CRCs ✓ Conducted 50 media interviews during PSPS event to inform the public	➢ Maintain readiness to implement PSPS ➢ Expand general preparedness beyond the FHCA
Public Safety Partner Coordination	Develop and implement a public safety partner engagement strategy to enhance coordination and ensure preparedness	✓ Completed 4 TTXs ✓ Attended 3 additional planning sessions ✓ Procured consulting services to begin portal development	➢ Complete 6 workshops ➢ Conduct 2 regional TTXs ➢ Perform 1 CRC demonstration ➢ PSPS portal development
Wildfire Safety & Preparedness Engagement Strategy	Manage a multi-pronged approach to engage and inform the public and customers regarding wildfire safety & preparedness	✓ 23 million impressions ✓ Over 34,500 clicks ✓ 20 news outlet interviews ✓ 5 engagement forums ✓ Webpage updates for Spanish translations ✓ 2,935 survey participants ✓ 6 CBO interviews	➢ Continue multi-pronged outreach campaign ➢ Incorporate feedback from 2022 customer and CBO surveys ➢ Continue to refine information for ease of use and access ➢ Identify community engagement opportunities with external stakeholders
Industry Collaboration	Participate in consortiums, forums, and advisory boards to collaborate with industry experts, maintain expertise in leading edge technologies and operational practices, and continue to improve and advance the WMP and its programs	✓ Actively participated in the OR Statewide Camera Interoperability Committee ✓ Participated in the California joint IOU workstreams	➢ OR Statewide Camera Interoperability Committee ➢ California joint IOU workstreams ➢ Leverage lessons learned from the IWRMC
Plan Monitoring & Implementation	Leverage a centralized, dedicated team to develop, monitor, implement, and continuously improve the WMP	✓ Investigated grant funding opportunities ✓ Developed a centralized repository of WMP related documentation	➢ Continue investigating grant funding and cost sharing opportunities ➢ Review QA/QC processes for program tracking

Plan Costs

Delivering Pacific Power's multi-year WMP, as summarized above, requires an increase in investment across multiple years. In 2022, Pacific Power invested approximately $20.3 million in capital and $32.9 million of expense to accomplish the plan elements. In addition, Pacific Power is currently forecasted and additional investment of $610 million through 2027 (across five years), or $440 million capital and $170 million expense. Some programs, as understood today, require finite investment with a planned end date, such as the replacement of expulsion fuses in the FHCA by the end of 2025 for $53.4 million or the installation of CFCIs in 2022 for $1.8 million. Other programs, such as enhanced inspections or vegetation management, are expected to be on-going and annual in nature. Additionally, the line rebuild program, which is particularly large and complex in scope, is forecasted to continue beyond 2027 consistent with the company's advancement in risk modeling. Furthermore, not all programs require spend of each type in each year.

The following tables describe Pacific Power's actual 2022 spend and current five-year estimate[31] of these incremental costs broken down by program and expenditure type. The values provided for actuals in 2022 represent best estimates or end of year forecasts based on the timing of the document preparation and all values provided are subject to change. Additionally, the capital costs included reflect spend occurring in a given year, which may differ from values included in GRC filings or cost recovery mechanism applications which include costs based on when assets are placed in service. Furthermore, the costs reflect Oregon's allocation of associated programs and projects and, finally, while the tables only include a five-year forecast, these programs and increased expenditure are expected to continue beyond 2027.

[31] Costs presented in Table 27 and 28 represent the most current estimates. These values could differ from the 2022 GRC filings and testimony prepared earlier in 2022.

Table 28: Planned Incremental Capital Investment by Program Category ($millions)

Program Category	2022 Actuals	2023	2024	2025	2026	2027	5 Year Total
Risk Modeling and Drivers	-	$0.4	-	-	-	-	$0.4
System Hardening	$17.5	$94.9	$106.4	$89.8	$73.2	$70.3	$434.6
Line Rebuild	*$3.6*	*$50.3*	*$68.8*	*$68.8*	*$68.8*	*$68.8*	*$325.3*
System Automation	*$4.5*	*$8.8*	*$10.5*	*$7.4*	*$2.7*	-	*$29.4*
Fuse Replacement	*$1.3*	*$23.1*	*$17.9*	*$11.1*	-	-	*$52.1*
Fault Indicators	*$1.8*	-	-	-	-	-	*$0.0*
System Allocated Transmission	*$6.4*	*$12.7*	*$9.2*	*$2.6*	*$1.7*	*$1.6*	*$27.8*
Situational Awareness	$1.8	$1.1	$0.8	$0.5	$0.4	$0.3	$3.2
Weather Station Installs	*$1.5*	*$0.9*	*$0.6*	*$0.2*	*$0.2*	*$0.1*	*$2.0*
Fire Impact Modelling	*$0.3*	*$0.2*	*$0.2*	*$0.2*	*$0.2*	*$0.2*	*$1.2*
Field Operations & Work Practices	$0.3	$0.7	-	-	-	-	$0.7
Public Safety Partner Coordination	$0.7	$1.3	-	-	-	-	$1.3
Grand Total	**$20.3**	**$98.5**	**$107.2**	**$90.3**	**$73.6**	**$70.6**	**$440.2**

Table 29: Planned Incremental Expense by Program Category ($millions)

Program Category	2022 Actuals	2023	2024	2025	2026	2027	5 Year Total
Risk Modeling and Drivers	$0.1	$0.5	$0.4	$0.4	$0.4	$0.4	$2.0
Inspection & Correction	$0.6	$0.8	$0.8	$0.8	$0.8	$0.8	$4.1
Vegetation Management	$24.0	$27.9	$23.8	$24.8	$24.3	$24.0	$124.9
Grid Hardening	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$1.6
Situational Awareness	$1.8	$1.8	$1.9	$1.9	$2.0	$2.0	$9.6
Field Operations & Work Practices	$2.8	$2.5	$2.5	$2.5	$2.5	$2.5	$12.7
PSPS Program	$2.2	$2.2	$1.8	$1.3	$0.8	$0.5	$6.5
Public Safety Partner Coordination	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$1.0
WMP Engagement Strategy	$0.5	$1.0	$0.8	$0.6	$0.6	$0.6	$3.6
Industry Collaboration	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.3
Plan Monitoring & Implementation	$0.6	$0.8	$0.8	$0.8	$0.8	$0.8	$3.8
Grand Total	**$32.9**	**$38.2**	**$33.3**	**$33.7**	**$32.7**	**$32.1**	**$169.9**

As this is the second WMP[32] submitted in Oregon, there is much to be learned and Pacific Power anticipates continuously improving its WMP in a way that aligns with community and Commission expectations. Key takeaways from collaborations with other utilities, Public Safety Partners, the Commission, communities and customers will be evaluated for incorporation into future WMPs and may require corresponding changes or updates to these forecasts.

Co-Benefits of Plan

Pacific Power's WMP encompasses various strategies, programs, and investments designed to reduce the risk of wildfire, in a manner consistent with emerging industry best practices. The elements of this plan provide clear benefits in the areas of wildfire mitigation, whether through enhanced inspections and corrections, additional vegetation management activities, or system hardening and the implementation of covered conductor. Additionally, maturation in the areas of risk mapping and situational awareness facilitate the prioritization and balancing of efforts to ensure the plan is delivered as efficiently as practical.

In identifying plan elements, Pacific Power considered both the costs and the benefits of any particular approach. Above all, Pacific Power's strategies were guided by the principle that the frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.

While the mitigation strategies in this plan are designed to reduce the risk of wildfire, many also offer significant co-benefits to the utility operation and its customers. For example, more frequent inspections can result in the identification and accelerated correction of additional

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[32] Pacific Power's first Oregon WMP, filed as the WPP consistent with Oregon Administrative Rule (OAR) 860-300-0002 on December 30, 2021, was approved by the Commission with direction to consider recommendations in Order No. 22-131 made effective on April 28, 2022.

conditions, which reduces wildfire risk. This same program can also improve public safety, worker safety, and reliability.

Similarly, system hardening provides one of the most beneficial ways to reduce wildfire risk, by increasing the level of localized weather conditions that can be tolerated without impact on the utility operations. For example, installing covered conductor will increase the grid's resiliency against wind-driven contacts. The mechanical properties of a covered conductor design physically prevent the initiation of a flash-over due to contact, mitigating wildfire risk. For this same reason, covered conductor also reduces the potential for outages, thereby providing significant reliability benefits.

Furthermore, Pacific Power's situational awareness capabilities provide multiple wildfire mitigation benefits by informing operational and field protocols and playing a key role in the facilitation of PSPS protocols and decision-making. Along the same lines, situational awareness, paired with operational readiness, provides co-benefits throughout the year by supporting Pacific Power's response to many types of emergency related events, such as winter storms. While the program is designed to mitigate wildfire risk, Pacific Power anticipates leveraging this new capability to support other types of emergency response and overall system resilience.

Finally, Pacific Power's WMP includes the use of new technologies, such as the implementation of advanced protection and control schemes. While key to reducing the potential for utility related spark events following a fault event, this equipment provides additional co-benefits in the areas of distribution system planning readiness. These projects lay the initial foundation for greater incorporation of other tactics, such as distribution automation or distributed generation.

Appendix A – Dynamic Modeling Data Inputs

The following describes the general model inputs, data sources, update frequency, and update plans for data included in the company's dynamic, seasonal risk model described in Section 5. Many of the data sources below are provided and managed by Technosylva.

Model Input	Data Source	Frequency of Update	Plan to Keep Updated
Transmission and distribution line assets by location and Zone of Protection (ZOP)	Pacific Power's asset management system	At least annual	Pacific Power will provide an at least annual update to Technosylva with changes to asset information
Forecast of the temperature, humidity, wind speeds and solar radiation for a 96-hour period at a 2 kM resolution	Pacific Power's Operational Weather Research & Forecast (WRF)	Twice daily	Received twice daily from NOAA and fed to WFA-E by Pacific Power
Historic weather conditions of the temperature, humidity, wind speeds and solar radiation at a 2 kM resolution	Pacific Power's 30-Year Weather Research & Forecast (WRF)	As needed	Pacific Power has provided eight years of the 30-Year WRF model to Technosylva for WFA-E and will continue providing historical years in batches until 30 years is complete and then move to an annual cadence to provide the prior year's data to stay current.
Real Time Weather Observations	Synoptic Mesonet accessible weather stations	Updated hourly	New weather stations are routinely added to the network and are automatically synched with WFA-E
Dead Fuels Moisture for one, ten, and 100-hr fuels are calculated using the Nelson Model at 2 kM resolution for a 96-hour period	Technosylva calculates with Pacific Power's Operational Weather Research & Forecast (WRF)	Updated daily	Updates contingent on updates to the operational weather forecast.
Live Fuels Moisture	Technosylva has developed a live fuel moisture based on satellite MODIS observations, phenology and weather data	Weekly	The herbaceous live fuel moisture model is continually improved as scarce observations become more available
Vegetation, wildland fuel, and fire regimes across	LANDFIRE, National Incident Field Service (NIFS), and other	Once prior to fire season and monthly during fire season	End of season, Beginning of season and monthly

Model Input	Data Source	Frequency of Update	Plan to Keep Updated
the United States and insular areas	ancillary data (such as Open Street Map Landuse Landcover) are converted to Technosylva's timber custom fuel types to improve the fire modelling. The fuels will be changing to the OBIA fuel model in 2023		during season with current fire scars
Satellite data of visible and infrared images and global observations of the land, atmosphere, cryosphere, and ocean, including visible and infrared images of hurricanes and detection of fires, smoke, and particles in the atmosphere, such as dust	GOES	Data is updated every five minutes	External service
Satellite that provides thermal anomalies/fire information that indicates a fire or hotspot	MODIS and VIIRS	Data is captured four times a day	External service
Information on fire location, perimeter, and acreage	IRWIN, Fireguard	Near real time	External service
Information on current wildfires	Alert Wildfire Camera Network, IRWIN	Near real time	External service
Historical Fire Information	NIFC-National Interagency Fire Center	Monthly during fire season	Update at end of wildfire season, beginning of season and monthly during season with current fire scars

Appendix B – Adherence to Requirements

OAR 860-300-0020 – Wildfire Mitigation Plan Filing Requirements

Consistent with OAR 860-300-0020 effective September 8, 2022, per Order No. 22-335:

(1) Wildfire Mitigation Plans and Updates must, at a minimum, contain the following requirements as set forth in Oregon Revised Statutes (ORS) 757.963 (2)(a)-(h) and as supplemented below:

Plan Requirement	Corresponding Plan Section / Reference
(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are: *(A) Within the service territory of the Public Utility, and* *(B) Outside the service territory of the Public Utility but within the Public Utility's right-of-way for generation and transmission assets.*	See Section 1.1 - Baseline Wildfire Risk for a description of how Pacific Power leveraged consulting services to identify the areas subject to a heightened risk of wildfire using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, the company's image and reputation, and financial implications. *See Figure 1: Study Area to Determine FHCA. *See Figure 3: Fire High Consequence Area (FHCA) Map
(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.	See Section 1.3 - Program Selection and Prioritization for how Pacific Power generally selects projects based on risk, Section 1.4 - Baseline Risk Assessment Projects and Improvements to understand how Pacific Power plans to incorporate risk reduction modelling and program effectiveness into decision making, and Section 13 - Plan Summary, Costs, & Benefits for total planned cost and a discussion on program benefits. decision making process.

Plan Requirement	Corresponding Plan Section / Reference
(c) *Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.*	See Sections 2 through 8 for a description of the preventative actions and programs Pacific Power carries out to minimize the risk of wildfire. Key preventative actions identified in plan include enhanced inspections and vegetation management, system hardening, situational awareness, system operations, field operations, and PSPS implementation. Additional supporting programs include risk assessment, public safety partner coordination, industry collaboration, and external engagement.
(d) *Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.*	See Section 9 - Public Safety Partner Coordination Strategy which outlines the general strategy and planned exercises and workshops to facilitate public and private sector coordination, validate communications protocols, and verify capability to support communities during extreme risk events. See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, for a description of how the company is engaging customers and the general public throughout its three-state service area on the topic of wildfire safety and preparedness through a variety of tactics including webinars, in-person forums, targeted paid media campaigns, press engagement.
(e) *Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure, including a PSPS communication strategy consistent with OAR 860-300-0040 through 860-300-0050.*	See Section 6 - System Operations for a description of how Pacific Power is adjusting power system operation through the implementation of Elevated Fire Risk (EFR) protection and control settings. See Section 7- Field Operations & Work Practices which includes how field operations managers deploy additional resources and perform additional patrols or augment work practices such as the deferral of any nonessential work at locations with dense and

Plan Requirement	Corresponding Plan Section / Reference
	dry wildland vegetation, especially during periods of heightened fire weather conditions. See Section 8 - Public Safety Power Shutoff (PSPS) Program for a description of the company's PSPS protocols
(f) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season, consistent with OAR 860-300-0040 and 860-300-0050.	See Section 9 - Public Safety Partner Coordination Strategy, for a description of Pacific Power facilitates annual discussion based and functional tabletop exercises to develop awareness of PSPS planning and procedures. See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, for a description of for the description of webinars, in-person forums, targeted paid media campaigns, press engagement, distributed print materials, social media updates, and communication through owned channels.
(g) Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0018.	See Section 2 - Inspection and Correction for a description of when an inspection is performed on a Pacific Power asset, inspectors use a predetermined list of condition codes (defined below) and priority levels (defined below) to describe any noteworthy observations
(h) Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0016.	See Section 3 - Vegetation Management for a description of Power's existing vegetation management program is to minimize contact between vegetation and power lines by addressing grow-in and fall-in risks.
(i) Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.	See Section 13 - Plan Summary, Costs, & Benefits

Plan Requirement	Corresponding Plan Section / Reference
(j) Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used to develop and implement cost effective wildfire mitigation solutions.	See Section 11- Industry Collaboration for a description of Pacific Power's membership in the International Wildfire Risk Mitigation Consortium (IWRMC),[14] an industry-sponsored collaborative designed to facilitate the sharing of wildfire risk mitigation insights.
(k) Description of ignition inspection program, as described in Division 24 of these rules, including how the utility will determine and instruct its inspectors to determine, condition that could pose an ignition risk on its own equipment and on pole attachments.	See Section 2.2 - FHCA Inspection and Correction Programs for a description of Pacific Power's FHCA inspection programs including a description of how fire threat conditions are determined, which reflects conditions that pose an ignition risk.

OAR 860-300-0030 – Risk Analysis

Risk Analysis Requirement	Corresponding Plan Section / Reference
(1) The Public Utility must include in its Wildfire Mitigation Plan risk analysis that describes wildfire risk within the Public Utility's service territory and outside the service territory of the public Utility but within the Public Utility's right of way for generation and transmission assets. The risk analysis must include, at a minimum:	See Section 1 - Risk Modeling and Drivers
(a) Defined categories of overall wildfire risk and an adequate discussion of how the Public Utility categorized wildfire risk. Categories of risk must include, at a minimum:	
A. Baseline wildfire risk, which includes elements of wildfire risk that are expected to remain fixed for multiple years. Examples include topography, vegetation, utility equipment in place, and climate;	See Section 1.1 - Baseline Wildfire Risk
B. Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year or from year to year; Examples include cumulative precipitation, seasonal weather conditions, current drought status, and fuel moisture content;	See Section 5 - Situational Awareness
C. Risks to residential areas served by the Public Utility; and	See Section 1.1 - Baseline Wildfire Risk, Section 5.4 - Seasonal Wildfire Risk, and Appendix A.
D. Risks to substation or powerline owned by the public Utility	See Section 1.1 - Baseline Wildfire Risk, Section 5.4 - Seasonal Wildfire Risk, and Appendix A.

Risk Analysis Requirement	Corresponding Plan Section / Reference
(b) A narrative description of how the public Utility determined areas of heightened risk of wildfire using the most updated data it has available from reputable sources.	See Section 1.1 - Baseline Wildfire Risk and Section 5 - Situational Awareness
(c) A narrative description of all data sources the Public Utility uses to model topographical and meteorological components of its wildfire risk as well as any wildfire risk related to the Public Utility's equipment. *A. The Public Utility must make clear the frequency with which each source of data is updated; and* *B. The Public Utility must make clear how it plans to deep its data sources as up to date as is practicable.*	For baseline risk, see Section 1.1 - Baseline Wildfire Risk and Section 1.5 - Future Baseline Risk Assessment Framework. For dynamic risk, see Section 5 - Situational Awareness and Appendix A – Dynamic Modeling Data Inputs
(d) The Public Utility's risk analysis must include a narrative description of ow the Public Utility's wildfire risk models are used to make decisions concerning:	
A. Public Safety Power Shutoffs	See Section 5.5 - Application & Use and Section 8 - Public Safety Power Shutoff (PSPS) Program.
B. Vegetation Management	See Section 1.1 - Baseline Wildfire Risk, Section 1.3 - Program Selection and Prioritization and Section 3 - Vegetation Management.
C. System Hardening	See Section 1.1 - Baseline Wildfire Risk, Section 1.3 - Program Selection and Prioritization and Section 4 - System Hardening.
D. Investment decisions; and	See Section 1.3 - Program Selection and Prioritization
E. Operational decisions.	See Section 5.5 - Application & Use, Section 6 - System Operations, and Section 7 - Field Operations & Work Practices.

Risk Analysis Requirement	Corresponding Plan Section / Reference
(e) *For updated Wildfire Mitigation Plans, the Public Utility must include a narrative description of any changes to its baseline wildfire risk that were made relative to the previous plan submitted by the utility, including the Public Utility's response to changes in baseline wildfire risk, seasonal wildfire risk, and Near-term Wildfire Risk.*	For baseline risk, see Section 1.1 - Baseline Wildfire Risk, and Section 1.5 - Future Baseline Risk Assessment Framework. For dynamic risk, see Section 5 - Situational Awareness and Appendix A – Dynamic Modeling Data Inputs
(2) *To the extent practicable, the Public Utility must confer with other state agencies when evaluating the risk analysis included in the Public Utility's Wildfire Mitigation Plan.*	See Section 9 - Public Safety Partner Coordination Strategy, Section 10 - Wildfire Safety & Preparedness Engagement Strategy, and Section 11 - Industry Collaboration.

OAR 860-300-0040 – Wildfire Mitigation Plan Engagement Strategies

Engagement Strategy Requirement	Corresponding Plan Section / Reference
(1) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Mitigation Plan Engagement Strategy. The Wildfire Mitigation Plan Engagement Strategy will describe the utility's efforts to engage and collaborate with Public Safety Partners and Local Communities impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum:	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy,
(a) Accessible forums for engagement and collaboration with Public Safety Partners, Local Communities, and customers in advance of filing the Wildfire Mitigation Plan. The public Utility should provide, at minimum:	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, and Section 9 - Public Safety Partner Coordination Strategy.
A. One public information and input session hosted in each county or group of adjacent counties within reasonable geographic proximity and streamed virtually with access and functional needs considerations; and	See Section 10.5 - Webinars and Community Forums
B. One opportunity for engagement strategy participants to submit follow-up comments to the public information and input session.	See Section 10.5 - Webinars and Community Forums
(b) A description of how the Public Utility designed the Wildfire Mitigation Plan Engagement Strategy to be inclusive and accessible, including considerations for multiple languages and outreach to access and functional needs populations as identified with local Public Safety Partners.	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy,

Engagement Strategy Requirement	Corresponding Plan Section / Reference
(2) *The Public Utility must include a plan for conducting community outreach and public awareness efforts in its Wildfire Mitigation Plan. It must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities.*	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, and Section 9 - Public Safety Partner Coordination Strategy.
(a) *The community outreach and public awareness efforts will include plans to disseminate informational materials and/or conduct trainings that cover:* A. *A description of PSPS including why one would need to be executed, considerations determining why one is required, and what to expect before, during, and after a PSPS;* B. *A description of the Public Utility's wildfire mitigation strategy;* C. *Information on emergency kits/plans/checklists;* D. *Public Utility contact and website information.*	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, and Section 9 - Public Safety Partner Coordination Strategy.
(b) *In formulating community outreach and public awareness efforts, the Wildfire Mitigation Plan will also include descriptions of:* A. *Media platforms and other communication tools that will be used to disseminate information to the public;* B. *Frequency of outreach to inform the public;* C. *Equity considerations in publication and accessibility, including, but not limited to:* (i) *Multiple languages*	Section 10 - Wildfire Safety & Preparedness Engagement Strategy

Engagement Strategy Requirement	Corresponding Plan Section / Reference
(ii) Multiple media platforms to ensure access to all members of a Local Community	
(3) The Public Utility must include in its Wildfire Mitigation Plan a description of metrics used to track and report on whether its community outreach and public awareness efforts are effectively and equitably reaching Local Communities across the Public Utility's service area.	See Section 10.6 - Campaign and Engagement Evaluation.
(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specific in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0050. The Coordination Strategy should include, at a minimum: *(a) Meeting frequency and location determined in collaboration with Public Safety Partners;* *(b) Tabletop Exercise plan that includes topics and opportunities to participate;* *(c) After action reporting plan for lessons learned in alignment with Public Safety partner after action reporting timeline and processes.*	See Section 9 - Public Safety Partner Coordination Strategy

OAR 860-300-0050 – Communication Requirements Prior, During, and After a Public Safety Power Shutoff (PSPS)

PSPS Communication Requirement	Corresponding Plan Section / Reference
(1) *When a Public Utility determines that a PSPS is likely to occur, it must deliver notification of the PSPS to its Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.*	See Section 8.4 - Communication Protocol
(a) *To the extent practicable, the Public Utility must provide priority notification directly to the Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.*	See Section 8.4 - Communication Protocol
(b) *In notifying Public Safety Partners and utility identified critical facilities of PSPS events, including adjacent local Public Safety Partners, the utility will communicate the following information, at a minimum:* A. *The PSPS zone, which would include Geographic Information System shapefile(s) depicting current boundaries of the area subject to a de-energization;* B. *Date and time PSPS will be executed;* C. *Estimated duration of PSPS;* D. *Number of customers impacted by the PSPS;* E. *When feasible, the Public Utility will support Local Emergency Management efforts to send out emergency alerts;* F. *At a minimum, status updates at 24-hour intervals until service has been restored;*	See Section 8.4 - Communication Protocol

PSPS Communication Requirement	Corresponding Plan Section / Reference
G. Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and *H. Information provided under this rule does not preclude the Public Utility from providing additional information about execution of the PSPS to its Public Safety Partners.*	
(c) In notifying utility-designated critical facilities, the Public Utility will communicate the following information, at a minimum: *A. Data and time PSPS will be executed;* *B. Estimated duration of PSPS;* *C. At a minimum, status updates at 24-hour intervals util service has been restored;* *D. Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and* *E. In addition to the above requirements, utilities will also provide Geographic Information Files with as much specificity as possible to Operators of Communications facilities in the area of the anticipated PSPS.*	See Section 8.4 - Communication Protocol
(d) ESF-12 will notify Oregon Emergency Response System (OERS) partners and Local Emergency Management in coordination with Oregon's Office of Emergency Management.	See Section 8.4 - Communication Protocol
(2) When a Public Utility determines that a PSPS is likely to occur, the Public Utility must provide advance notice of the PSPS to customers via a PSPS web-based interface on the Public Utility's website and other media platforms and may communicate PSPS information directly with customers consistent with this rule.	See Section 8.4 - Communication Protocol, Section 9.8 - Public Safety Partner Portal, and Section 10.4 - Wildfire Safety, Preparedness and PSPS Webpages

PSPS Communication Requirement	Corresponding Plan Section / Reference
(a) In providing notice to customers about a PSPS, the Public Utility will, at a minimum: *A. Utilize multiple media platforms to maximize customer outreach, including but not limited to, social media, radio, television, and press releases;* *B. Consider the geographic and cultural demographics of affected areas, including but not limited to broadband access, languages prevalent within the utility's service territories, considerations for those who are vision or hearing impaired; and* *C. Display on its website homepage a prominent link to access current information about the PSPS, consistent with OAR 860-300-0060, including a depiction of the boundary. The PSPS information must be easily readable and accessible from mobile devices.*	See Section 8.4 - Communication Protocol and Section 10.4 - Wildfire Safety, Preparedness and PSPS Webpages
(b) The Public Utility may directly notify its customers through email communication or telephonic notification (e.g., text messaging and phone calls) when it will not impede Local Emergency Management alerts due to capacity limitations. If the Public Utility provides direct notification, the Public Utility will communication the following information, at a minimum: *A. A statement of impending PSPS execution, including an explanation of what a PSPS is and the risks that the PSPS would be mitigating;* *B. Date and time PSPS will be executed;* *C. Estimated duration of PSPS;*	See Section 8.4 - Communication Protocol

PSPS Communication Requirement	Corresponding Plan Section / Reference
D. A 24-hour means of contact customers may use to ask questions or seek information; *E. How to access details about the PSPS via the Public Utility's website, including education and outreach materials disseminated in advance of the annual wildfire season;* *F. After initial notification, the Public Utility will provide, at a minimum, status updates at 24-hour intervals until the conditions prompting the PSP have ended; and* *G. Notice of when re-energization efforts will begin and when re-energization is expected to be complete.*	
(3) To the extent possible, the Public Utility will adhere to the following minimum notification prioritization and timeline in advance of a PSPS; *(a) 48-72 hours in advance of anticipated de-energization, priority notification to Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners;* *(b) 24-48 hours in advance of anticipated de-energization, when safe: secondary notification to all other affected customers; and* *(c) 1-4 hours in advance of anticipated de-energization, if possible: notification to all affected customers.*	See Section 8.4 - Communication Protocol
(4) The Public Utility's communications required under this rule do not replace emergency alerts initiated by local emergency response.	See Section 8.4 - Communication Protocol

PSPS Communication Requirement	Corresponding Plan Section / Reference
(5) *Nothing in this rule prohibits the Public Utility from providing additional information about the execution of the PSPS to Public Safety Partners, utility-identified critical facilities, or customers.*	See Section 8.4 - Communication Protocol

OAR 860-300-0060 – Ongoing Informational Requirements for Public Safety Power Shutoffs (PSPS)

PSPS Informational Requirement	Corresponding Plan Section / Reference
(1) The Public Utility will create a web-based interface that includes real-time, dynamic information non location, de-energization duration estimates, and re-energization estimates. The web-based interface will be hosted on the Public Utility's website and must be accessible during a SPSP event. The Public Utility will complete the web-based interface before March 31, 2024.	See Section 9.8 - Public Safety Partner Portal and Section 10.4 - Wildfire Safety, Preparedness and PSPS Webpages
(2) The Public Utility will make its considerations when evaluating the likelihood of a PSPS publicly available on its website. These considerations include, but are not limited to: strong wind events, other current weather conditions, primary triggers in high risk zones that could cause a fire, and any other elements that define an extreme fire hazard evaluated by the Public Utility.	See Section 9.8 - Public Safety Partner Portal and Section 10.4 - Wildfire Safety, Preparedness and PSPS Webpages
(3) The Public Utility will ensure that its website has the bandwidth capable of handling web traffic surges in the event of a Public Safety Power Shutoff.	See Section 9.8 - Public Safety Partner Portal and Section 10.4 - Wildfire Safety, Preparedness and PSPS Webpages
(4) The Public Utility will work to provide real-time geographic information pertaining to PSPS outages compatible with Public Safety Partner GIS platforms.	See Section 9.8 - Public Safety Partner Portal

OAR 860-300-0070 – Reporting Requirements for Public Safety Power Shutoffs (PSPS)

PSPS Reporting Requirement	Corresponding Plan Section / Reference
(1) The Public Utility is required to file annual reports on de-energization lessons learned, providing a narrative description of all PSSP events which occurred during the fire season. Reports must be filed not later than December 31st of each year.	See Pacific Power's Annual PSPS Report also referenced in Section 8.7 - 2022 Experience.
(2) Non-confidential versions of the reports required under this section must also be made available on the Public Utility's website.	See Pacific Power's Annual PSPS Report also referenced in Section 8.7 - 2022 Experience.

Appendix C – Staff Recommendations

Consistent with Order No. 22-131 effective April 28, 2022, Pacific Power considered the following recommendations from Staff in the development of the 2023 WMP:

Staff Recommendation	Consideration
(1) *Pacific Power include details of the analysis completed to identify the riskiest specific asset features, such as conductor type. With distribution hardening projects in the PSPS Zones projected to take eight years, understand how projects are being prioritized based on varying asset risk levels.*	See Section 1.2 Risk Drivers for a description of an understanding of risk drivers informs specific mitigation tactics or strategies that can be used to reduce the total amount of risk associated with utility operations. See Section 1.3 - Program Selection and Prioritization to understand how projects have been selected and prioritized See Section 1.4 - Baseline Risk Assessment Projects and Improvements to understand how projects will be selected and prioritized moving forward.
(2) *Pacific Power include the analysis of comparing measured risk reduction of plan activities to their costs, a cost-benefit analysis*	See Section 1.4 - Baseline Risk Assessment Projects and Improvements for a description of projects planned to enable a risk reduction analysis in the future. Additionally, see Section 13 - Plan Summary, Costs, & Benefits for a summary of the 2022 WMP actuals, future planned costs, and plan benefits.
(3) *Pacific Power includes a description of how the overall effectiveness of the plan activities will be measured, as well as information on wildfires in the service territory for the prior year.*	See Section 1.4 - Baseline Risk Assessment Projects and Improvements for a description of projects planned to enable effectiveness tracking and measurement.
(4) *Pacific Power provide details of how the objectives of individual key preventative actions have been met or not met, from the prior year of system operation.*	See Section 13 - Plan Summary, Costs, & Benefits for a description of 2022 accomplishments.

Staff Recommendation	Consideration
(5) *Pacific Power further demonstrates to what degree the preventable measure has reduced the risk of the utility's infrastructure from the cause of fire.*	See Section 1.4 - Baseline Risk Assessment Projects and Improvements for a description of projects planned to enable risk reduction scenario modeling.
(6) *Pacific Power include clarification about Community Resource Centers (CRC) in its 2023 WMP Update.*	See Section 8.5 - Community Resource Centers for a description of Pacific Power's CRC services and protocols.
(7) *Pacific Power to provide clarification about Community Resource Centers (CRC) in their 2022 emergency training and exercise imminent events.*	See Section 8.5 - Community Resource Centers for a description of Pacific Power's CRC services and protocols. Additionally, see Section 9 - Public Safety Partner Coordination Strategy for how CRC planning will be incorporated into the 2023 exercises and workshops.
(8) *Pacific Power to include a more robust description for the re-energization stage of a PSPS in its 2023 WMP Update.*	See Section 8.6 - Re-Energization for a description of Pacific Power's re-energization stage of PSPS.
(9) *Pacific Power includes previous year's lessons learned regarding de-energization of power lines in its 2023 WMP Update.*	See Section 8.7 - 2022 Experience for a description of Pacific Power's 2022 PSPS experience. See Section 9 - Public Safety Partner Coordination Strategy for a description of how 2022 experienced shaped the 2023 preparedness strategy.

Staff Recommendation	Consideration
(10) Pacific Power to include more information on where and when the modifications to its power system are being deployed.	See Section 6 - System Operations for a description of operations adjustments including the implementation of EFR settings and modifications to re-energization testing protocols. Additionally, see Section 5.5 - Application & Use for how Pacific Power's Situational Awareness program is informing these modifications based on risk.
(11) Pacific Power include more information on what conditions trigger the modifications, who makes the decision to modify operations, and the analysis used to make such decisions.	See Section 5.5 - Application & Use for how Pacific Power's Situational Awareness program is informing decisions. For system modifications, see Section 6 - System Operations. For PSPS protocols, see Section 8 - Public Safety Power Shutoff (PSPS) Program.
(12) Pacific Power include enhanced description of the outreach efforts in its 2023 WMP Update.	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, for general outreach. Specific to public safety partners, also see Section 9 - Public Safety Partner Coordination Strategy for a description.
(13) Pacific Power include a discussion about community outreach and public awareness efforts as part of its 2022 emergency training and exercise imminent events, to clarify these activities, and to solicit input from participating Stakeholders.	See Section 10 - Wildfire Safety & Preparedness Engagement Strategy, for general outreach. Specific to public safety partners, also see Section 9 - Public Safety Partner Coordination Strategy for a description.

Staff Recommendation	Consideration
(14) Pacific Power to provide reasoning, or an explanation of the analysis, used for choosing the shortened inspection frequencies. For example, for overhead distribution and transmission less than 200 kV, the detailed inspection frequency is shortened from 10 to 5 years in FHCAs. No summary of the analysis is provided that supports the inspection frequency, such as the type and volume of fire threat conditions found in FHCAs historically or fire threat conditions in the FHCAs that have caused wildfires in the past. It is unclear what information drove the decisions of the FHCA inspection frequencies chosen. Supportive information demonstrating how historical efforts have confirmed the success of modified procedural or operational changes is lacking.	See Section 2.2 - FHCA Inspection and Correction Programs for a description of program reasoning.
(15) Pacific Power provide more information regarding their quality control/quality assurance program and audits for vegetation management work completed in the FHCAs; measures employed, frequency, and resource types.	See Section 3.3- Post Work Audits for a description of vegetation management quality control/quality assurance activities.
(16) Pacific Power provides any analysis of historical events pertaining to Pacific Power's power lines, specific equipment type, vegetation, and wildfires.	See Section 1.2 - Identification of Risk Drivers for an analysis of historic risk events.

Staff Recommendation	Consideration
(17) Pacific Power includes a summary of the quantitative analysis used in the choice and prioritization of specific solutions and investments.	See Section 1.2 Risk Drivers for a description of an understanding of risk drivers informs specific mitigation tactics or strategies that can be used to reduce the total amount of risk associated with utility operations. See Section 1.3 - Program Selection and Prioritization to understand how projects have been selected and prioritized. Additionally, see Section 1.4 - Baseline Risk Assessment Projects and Improvements to understand how projects will be selected and prioritized moving forward.
(18) Pacific Power discuss the impact of participation in expert forums on identification of solutions most like to provide the benefits anticipated.	See Section 11 Industry Collaboration for a description of Pacific Power membership and participation in industry networks to inform solutions.
(19) Pacific Power includes more specific details on what it has learned by participating in these groups. Staff would like assurance the Company is leveraging the learnings from other utilities to facilitate implementation of solutions with the highest benefit cost ratio.	See Section 11 Industry Collaboration.

PACIFIC POWER

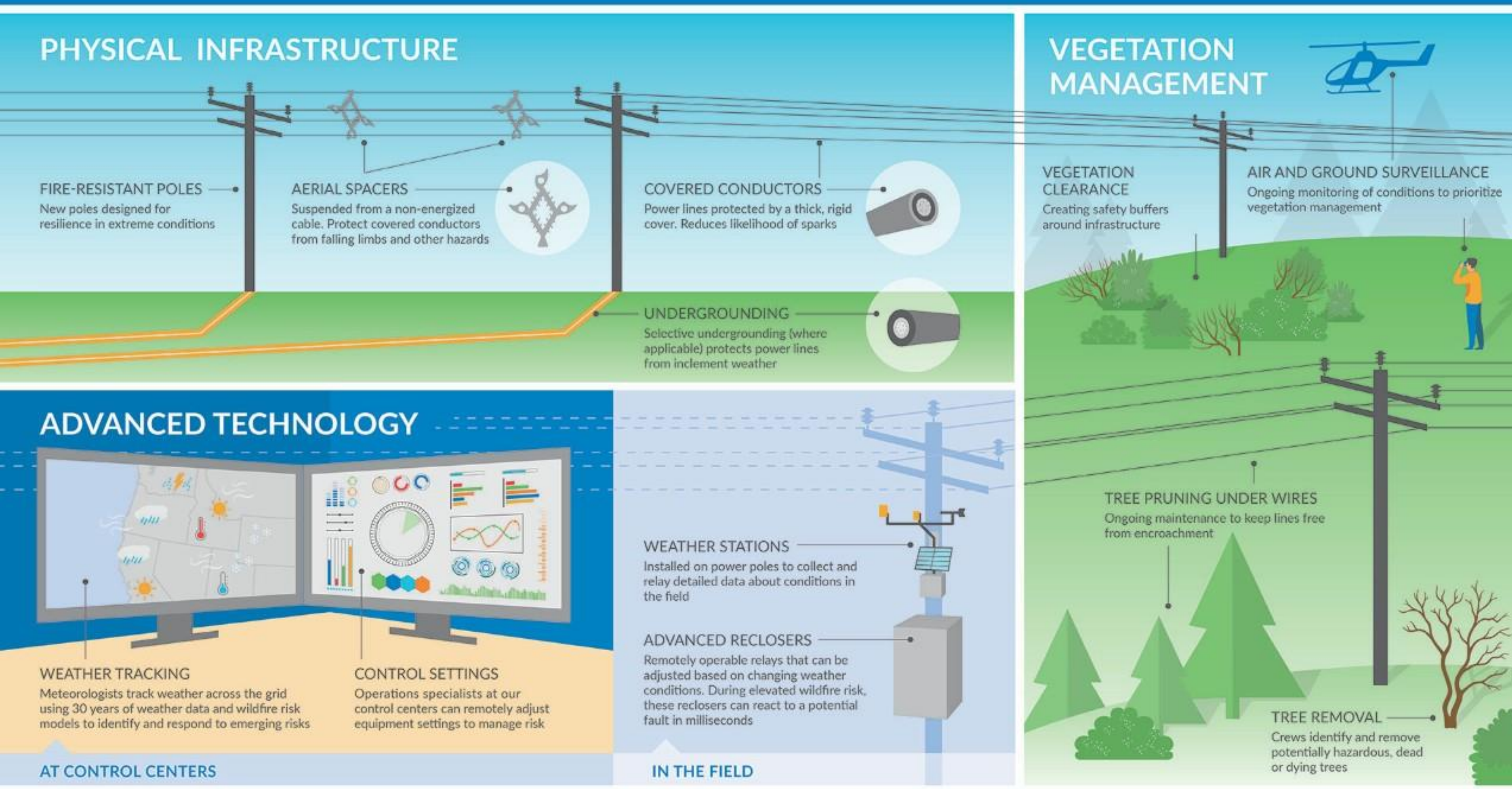
POWERING YOUR GREATNESS

A FUTURE-READY GRID

PACIFIC POWER.

Safety and service reliability are our top priorities. As extreme weather conditions and elevated wildfire risk become more common, we're making important updates across our system, building a hardened, future-ready grid.

- Installing thousands of miles of covered wires, fire-resistant poles and more
- Expanding our vegetation management practices to address emerging risks
- Integrating advanced technology and a dedicated meteorology team to better understand weather's impact on our system and respond in real time



With this layered approach, we're reducing risk and investing in resilience and reliability for the long term.

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

December 21, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

RE: AR 638 – Rulemaking for Risk-based Wildfire Protection Plans and Planned Activities Consistent with Executive Order 20-04 / UM 2208 – PGE's Wildfire Protection Plan

Dear Filing Center:

Please find attached the Portland General Electric Company ("PGE") 2023 Wildfire Mitigation Plan (WMP) which is being submitted as required per Oregon Administrative Rule 860-300-0002(2).

PGE continues to evolve its approach to mitigating the risk of wildfires in response to changing conditions. For example, we slightly expanded a few of our High Fire Risk areas and reduced one as well due to continued refinements made to our 2022 risk analysis. In addition, PGE will continue to expand its situational awareness capabilities through new Pano-AI camera installations and weather stations. These efforts are in addition to the operational changes that occur during fire season, capital investments to harden our system and our inspection and vegetation management activities. PGE anticipates that our WMP will continue to evolve as our risk assessment and wildfire mitigation capabilities expand.

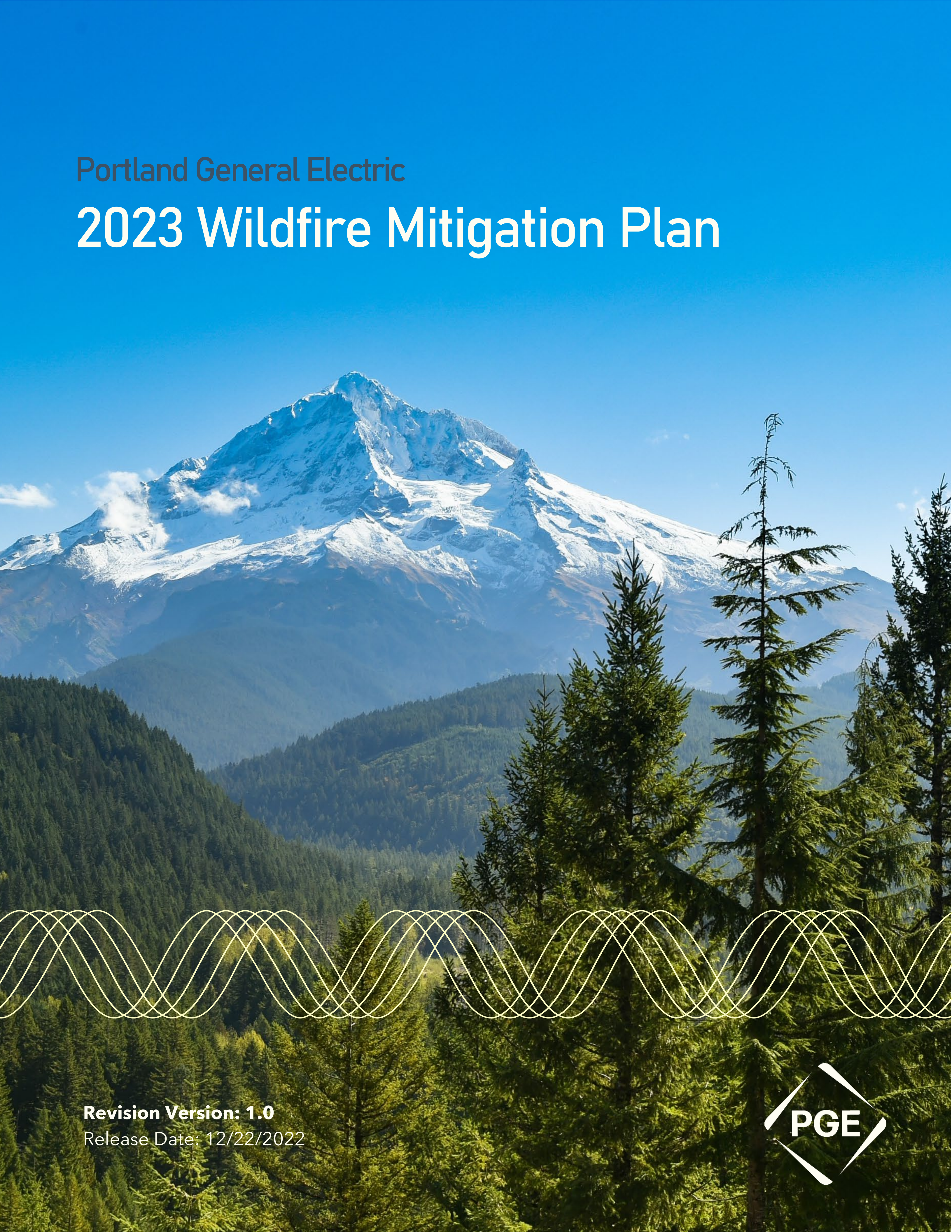
PGE appreciates Staff's efforts to establish permanent rules regarding utilities' wildfire mitigation plans. PGE looks forward to the review of the 2023 WMP. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Respectfully Submitted,
/s/ W. M. Messner

William M. Messner
Director Wildfire Mitigation & Resiliency

Portland General Electric

2023 Wildfire Mitigation Plan



Revision Version: 1.0

Release Date: 12/22/2022

This Wildfire Mitigation Plan (WMP) contains statements that relate to future plans, objectives, expectations, performance, and events. These forward-looking statements represent PGE's estimates and assumptions as of December 1, 2022; because PGE is continually updating its wildfire data, information included in the WMP reflects the data available at the time of publication. Furthermore, the estimated costs and schedules contained herein are subject to certain uncertainties including delays in supply chain and increased supply costs, nonperformance of counterparties and employee work factors. PGE assumes no obligation to update or revise any forward-looking statement as a result of new information, future events, or other factors.

These forward-looking statements are not a guarantee of future performance, and any such forward-looking statements are subject to risks and uncertainties which may be difficult to predict or are beyond PGE's control. As a result, actual results may differ materially from those projected in the forward-looking statements.

1. Executive Summary

PGE's Wildfire Mitigation & Resiliency (WM&R) organization plans and implements the Wildfire Mitigation Program (Program), developing and coordinating wildfire mitigation activities across the company. The company's approach to wildfire mitigation continues to evolve in response to both global climate change, which is fueling landscape-altering wildfire events worldwide, and to the wildfire rules recently issued by the Oregon Public Utility Commission (OPUC). PGE's goal is to improve regional safety by reducing the risk that PGE's electric utility infrastructure could cause a wildfire, while limiting the impacts of Public Safety Power Shutoff (PSPS) events and other mitigation activities on customers and increasing the resiliency of PGE assets to wildfire damage.

In compliance with OPUC rules governing wildfire protection plans, the Wildfire Mitigation Plan (WMP) describes PGE's approach to wildfire risk mitigation and guides the company's Program.

The WMP presents PGE's approach to risk modeling, which is the foundation of the Program. The risk model, referred to as the "Wildfire Risk Mitigation Assessment," provides guidance for the major Program focus areas: operating protocols, PSPS events, asset management and inspections, vegetation management, Public Safety Partner and community engagement, public awareness and outreach, and research and development.

For 2023, the updated Wildfire Risk Mitigation Assessment resulted in PGE maintaining its 10 existing High Fire Risk Zones (HFRZs) with some minor refinements. HFRZs are areas within PGE's service territory where vegetation, terrain, meteorological patterns, and wildland-urban interface considerations increase the risks associated with wildfire. PGE implements specific inspection and maintenance, vegetation management, and operational actions within these HFRZs during and in preparation for PGE's declared Fire Season for improved ignition prevention and safety.

In addition, PGE continues to expand its situational awareness capabilities, including measures such as installing new remote automated weather stations and artificial intelligence (AI)-enhanced ultra-high-definition cameras (Pano AI cameras) to automatically notify PGE and its Public Safety Partners when they detect a fire, in real time. PGE will continue to invest in mitigations to reduce wildfire risk throughout our system.

However, factors beyond PGE's control, including rising costs and other supply chain issues, changing weather patterns driven by climate change, and competition for limited contract resources for vegetation management and inspections, will continue to impact delivery of PGE's Program in 2023. Investor-owned utilities, the OPUC, and other stakeholders must strive to achieve a reasonable balance between affordable electricity rates and meaningful wildfire risk reduction.

At PGE, wildfire-related planning, mitigation, and research are year-round endeavors. PGE may update this WMP and the Program throughout the year to address new findings, data, and analysis. PGE will continue to work collaboratively with Public Safety Partners, Tribes, local communities, and other key stakeholders to prioritize the safety of people, property, and public spaces.

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Glossary and Acronyms

AAR: After-Action Review

AGOL: ArcGIS Online

ANSI: American National Standards Institute

APPA: American Public Power Association

AWRR: Advanced Wildfire Risk Reduction

Blue-Sky/Grey-Sky Events: During Blue-Sky events, a utility executes normal daily operations with no natural disasters or other disruptive events. A Grey-Sky event refers to an operating day or days in which a utility faces severe weather or other incident which causes reliability concerns, and all hands are on deck to respond to the incident.

BPA: Bonneville Power Administration

CBO: Community-Based Organization

CEOP: Corporate Emergency Operations Plan

CIMT: Corporate Emergency Management Team

CPC: Climate Prediction Center

CRC: Community Resource Center

DEI: Diversity, Equity & Inclusion

EAC: Equivalent Annual Cost

ECC: Emergency Coordination Center

EEI: Edison Energy Institute

EEMT: Energy Emergency Management Team

EFD: Early Fault Detection

EOC: Emergency Operations Center

EPRI: Electric Power Research Institute

ESCC: Electricity Subsector Coordinating Council

ESF-12: Refers to Emergency Support Function-12 and indicates the Public Utility Commission of Oregon's role in supporting the State Office of Emergency Management for energy utilities' issues during an emergency, per OAR 860-300-0002(1).

FAQ: Frequently Asked Question

FDRA: Fire Danger Rating Area

Fire Season: Period(s) of the year during which wildland fires are most likely to occur, spread, and affect resources sufficiently to warrant organized fire management activities

Fire Weather: Weather conditions that influence fire ignition, behavior, and suppression

FITNES: Facilities Inspection & Treatment to National Electrical Safety Code

GIS: Geographic Information System

High Fire Risk Zone (HFRZ): Geographic areas at elevated risk of wildfire ignition identified by PGE in its risk-based WMP

HSEEP: Homeland Security Exercise & Evaluation Program

IAM: Institute of Asset Management

IAP: Incident Action Plan

ICP: Incident Command Post

IMT: Incident management Team

IRWIN: Integrated Reporting of Wildland Fire Information

IWRMC: International Wildfire Risk Mitigation Consortium

ISO: International Organization for Standardization

LCES: Lookouts, Communications, Escape Routes, and Safety Zones

LiDAR: Light Detection & Ranging

Local Community: Any community of people living, or having rights or interests, in a distinct geographical area, per OAR 860-300-0002(2)

Local Emergency Management: Refers to city, county, and Tribal emergency management entities, per OAR 860-300-0002(3)

NICC: National Interagency Coordination Center

NIFC: National Interagency Fire Center

NIMS: National Incident Management System

No-Test Policy: PGE will disable auto-reclosing and not manually close-in a faulted circuit

NRECA: National Rural Electric Cooperative Association

NWCC: Northwest Coordination Center

NWS: National Weather Service

OAR: Oregon Administrative Rule

ODF: Oregon Department of Forestry

ODHS: Oregon Department of Human Services

ODOT: Oregon Department of Transportation

OH: Overhead (transmission or distribution circuit)

OJUA: Oregon Joint Use Association

O&M: Operations and Maintenance

OPUC: Public Utility Commission of Oregon

P1: Hazard/danger tree

P2: A tree that poses a grow-in or fall-in threat and displays arboricultural defect that poses risk to PGE facilities

PGE: Portland General Electric

PMO: PGE's Project Management Office

PSA: Predictive Service Area

PSPS: Public Safety Power Shutoff

Public Safety Partners*:* Includes the ESF-12, Local Emergency Management, and Oregon Department of Human Services (ODHS), per OAR 860-300-0002(6)

QA/QC*:* Quality Assurance/Quality Control

RAWS: Remote Automated Weather Station

Red Flag Warning*:* A term used by the National Weather Service to alert forecast users of an ongoing or imminent critical fire weather pattern. Red Flag Warnings will be issued whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, the National Fire Danger Rating System (NFDRS) is high to extreme, and all of the following weather parameters are forecasted to be met:

- Ten-hour fuels (moisture content of small vegetation that take only about 10 hours to respond to changes in moisture conditions) of 8 percent or less
- A sustained wind average 15 mph or greater.
- Relative humidity less than or equal to 25%.
- A temperature of greater than 75 degrees Fahrenheit.

In some states, dry lightning and unstable air are criteria. A Fire Weather Watch may be issued prior to the Red Flag Warning.

ROW: Right-of-way

RSE*:* Risk-Spend Efficiency

RVM: Routine Vegetation Management

SB: Senate Bill

SCADA: Supervisory Data Control & Acquisition

SEL: Schweitzer Engineering Laboratories

SME: Subject Matter Expert

Supervisory Control and Data Acquisition (SCADA)*:* The control system architecture comprising computers, networked data communications and graphical user interfaces (GUI) for high-level process supervisory management, while also comprising other peripheral devices like programmable logic controllers (PLC) and discrete proportional-integral-derivative (PID) controllers to interface with process plant or machinery.

Striking Distance*:* A term used to describe a tree that has the potential to impact PGE powerlines and other equipment.

T&D: Transmission and Distribution

Tier 1 Risk: Describes an area where there is not an elevated or extreme risk of wildfires.

Tier 2 (Elevated) Risk*:* Describes an area where there is an elevated risk (including likelihood and potential impacts on people and property) of utility-associated wildfires.

Tier 3 (Extreme) Risk: Describes an area where there is an extreme risk (including likelihood and potential impacts on people and property) of utility-associated wildfires.

Tribes: this term is used collectively to describe PGE's Tribal partners, including the Confederated Tribes of the Grande Ronde, Confederated Tribes of Warm Springs, *Confederated* Tribes of the Umatilla Indian Reservation, and Confederated Tribes of Siletz Indians.

UAM: PGE's Utility Asset Management program

USDOE: United States Department of Energy

USFS: United States Forest Service

Utility-Identified Critical Facilities: the facilities identified by PGE within its service territory that have the potential to threaten life safety or disrupt essential socioeconomic activities if their services are interrupted. Communications facilities and infrastructure are considered Critical Facilities.

Wildfire Risk Mitigation Assessment: a PGE program that models and assesses a wide range of potential wildfire-related risk factors to inform PGE's operational and financial decision-making.

WMP: Wildfire Mitigation Plan

WM&R: PGE's Wildfire Mitigation & Resiliency organization

2. Introduction

This WMP describes PGE's wildfire prevention and mitigation efforts and PGE's planned activities to prevent utility-caused wildfire ignition events. The WMP incorporates internal and external lessons learned from the 2022 Fire Season and describes PGE's wildfire preparedness and response activities for 2023.

The success of the Program relies on the active participation of a broad spectrum of internal and external stakeholders under the direction of PGE's WM&R organization. The foundation of the Program is PGE's Wildfire Risk Mitigation Assessment and Risk Spend Efficiency calculations, used to develop and guide Program activities and wildfire mitigation investments. Based on industry benchmarking and findings from its Wildfire Risk Mitigation Assessment, PGE believes that the frequency of utility-caused ignition events can be reduced through:

- Inspection and maintenance of poles and equipment
- Engineering of reliable systems that experience fewer events that result in spark failure modes (potential ignitions)
- System hardening
- Effective vegetation management
- Situational awareness and operational readiness
- Operational changes during Fire Season, including the use of system protection devices such as electronic reclosers
- Effective use of PSPS to prevent utility-caused ignitions during Red Flag Warning meteorological events.

PGE will review its Fire Season operations and wildfire mitigation preparedness and response actions on an annual basis and update the WMP as needed. PGE will also update the WMP as required to comply with applicable regulatory requirements or changes in laws or regulations. If PGE substantively updates the plan outside of the annual submission cycle, PGE will refile the WMP with the OPUC and post the most current version of the WMP on PGE's website.

Some of the most important changes made for the 2023 WMP include the ongoing evolution of PGE's Wildfire Risk Mitigation Assessment in partnership with PGE's Public Safety Partners (please refer to Section 6.2, Updates to 2023 Wildfire Risk Mitigation Assessment, for additional details). PGE also expanded its situational awareness capabilities by adding 22 Pano AI fire detection cameras covering all 10 of PGE's HFRZs. Over 30 fire agencies have direct access to this technology, potentially improving response time to fires in the areas they serve. In addition, PGE's weather station network now consists of 52 stations providing weather data at a micro level, allowing for more precisely informed PSPS decision-making. PGE continues to move forward with non-expulsion fuse installation and other ignition prevention investments, such as tree wire and undergrounding projects. Other capital improvements include the expanded use of intelligent reclosers to reduce the number of customers impacted by PSPS events.

Lastly, in September 2022, PGE executed a PSPS event in all 10 of PGE's pre-designated HFRZs. This decision was not taken lightly, as it directly impacted customers across the PGE service territory. PGE observed damage to PGE assets from limbs and trees, indicating that the PSPS likely prevented wildfire ignitions within the PGE HFRZs during a period of extreme fire potential conditions, with Red Flag Warnings in effect from the Cascade Range to the Coast Range. Please refer to Appendix 8 (Summary of Input from Public Safety Partners and Lessons Learned Captured During the 2022 Fire Season) for lessons learned and recommendations from the PSPS event, tabletop exercises, and collaboration with PGE's Public Safety Partners.

3. Purpose and Scope

PGE's WMP is designed to provide strategic direction for the programs and activities that seek to mitigate the potential for PGE equipment, facilities, or activities to become wildfire ignition sources, and to guide PGE's compliance with all applicable laws and regulations, including the OPUC's wildfire rules. In constructing the WMP, PGE observed the following key principles:

- Prioritize public and employee safety
- Act to reduce the risk of wildfire ignitions from PGE assets
- Provide effective guidance to inform PGE's Fire Season operations
- Guide PGE's system hardening activities, increasing resistance to wildfire impacts through a systematic, risk-based approach to identifying and prioritizing system hardening and resiliency activities
- Communicate and collaborate with industry peers and Public Safety Partners, Emergency Support Function 12 (ESF-12), local emergency managers, Oregon Department of Human Services, local communities and community-based organizations, counties, Federal, Tribal, State and local governments, operators of PGE-identified critical facilities, and customers
- Maintain reliable electric service, and
- Implement PSPS events with efficiency, when necessary, and with broad public awareness.

4. Operating Environment and Service Territory

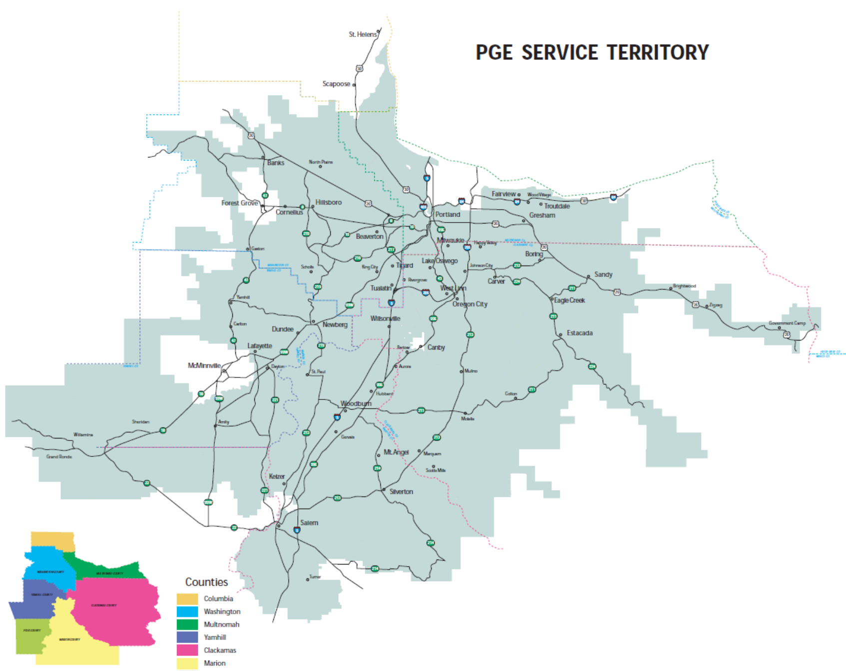
4.1 Operating Environment

Global climate change continues to alter the Pacific Northwest climate in ways that are difficult to model and predict. This reality will drive continuous evaluation and modification of PGE's WMP for the foreseeable future. In addition, the effects of climate change on California and resulting wildfires have increasingly pulled West Coast wildfire mitigation resources to the south, intensifying competition for available fire suppression, inspection, and vegetation management resources in the Pacific Northwest.

4.2 PGE Service Territory – Overview

PGE's service territory is distributed over 4,000 square miles in a combination of forested, mountainous, urban, and suburban environments. Much of the eastern and western portions of PGE's service area are forested, particularly in the Mt. Hood corridor along Highway 26, in the foothills of the Coast Range, and south toward Estacada. While the majority of PGE's service territory is located within the most densely populated area of the state, PGE's managed right-of-way (ROW) contains more than 2.2 million trees, with millions more off-ROW trees. In managing off-ROW conditions, PGE must coordinate with multiple neighboring utilities that interconnect to our system, including the Bonneville Power Administration (BPA), PacifiCorp, West Oregon Electric Cooperative, Wasco Electric Cooperative, Consumers Power, Inc., Forest Grove Light & Power, and McMinnville Water and Light.

Figure 1: PGE Service Territory



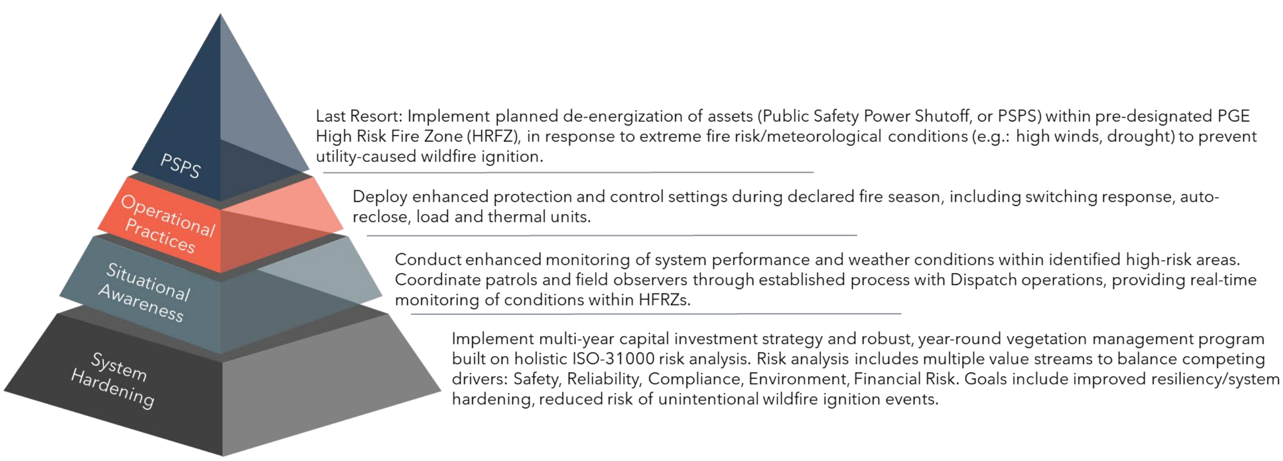
5. Wildfire Risk Mitigation Program Overview

PGE's primary wildfire risk mitigation objective is to reduce the risk of ignition from PGE assets, while limiting the impacts of specific mitigation activities, such as PSPS events, on customers. The Program can be broken down into the following four risk mitigation approaches and associated objectives:

- **PSPS:** Identify areas of heightened wildfire threat (HFRZs) within the PGE service territory and mitigate the risk of PGE-caused wildfire ignition in those areas through planned de-energizations (PSPS events) during periods of extreme fire risk.
- **Operational Practices:** Implement operational system settings, including protection systems (e.g., reclosers), line and vegetation maintenance, and using a risk-informed protection strategy to reduce risk of ignitions.
- **Situational Awareness:** Improve PGE's wildfire-related risk management and situational awareness capabilities.
- **System Hardening:** Implement a systematic, risk-informed approach to identify and prioritize system hardening, and resiliency measures to reduce the likelihood of ignitions caused by utility assets and protect PGE assets from damage.

The following figure provides a visual representation of PGE's multi-layered approach to wildfire risk mitigation:

Figure 2: PGE's Wildfire Risk Mitigation Hierarchy



PGE strives to find cost-effective ways to maximize wildfire risk reduction by applying risk assessment modeling to guide mitigation strategies. The purpose of this work is to deliver highest risk reduction per dollar spent on mitigation. Wildfire Risk Mitigation Assessment methodologies and mitigation measures are discussed in more detail in Section 6 of the WMP.

6. Wildfire Risk Assessment and Mitigation Activities

6.1 Risk Assessment Overview

PGE uses a multi-phase wildfire risk assessment program to:

- Annually identify and refine the boundaries of the HFRZs within the PGE service territory
- Quantify the likelihood that individual PGE assets could contribute to ignition of large wildfires (>100 hectares for fires in timber; >400 hectares for fires in grass or rangeland), map their location, and apply a consequences model to determine where a potential wildfire ignition would be most significant.

The annually updated HFRZ assessment enables PGE to identify the highest-risk areas within its service territory (HFRZs are discussed in Section 7, below) and prioritize wildfire mitigation actions. The model results are a key input to the development of PGE's 2023 WMP. In addition, PGE evaluates wildfire risk across PGE transmission and generation assets outside of our service territory (refer to Appendix 9, PGE Wildfire Risk Assessment Overview & Process, for additional details).

Assessment results allow PGE to evaluate susceptibility to the natural and human factors that could contribute to electric asset-caused wildfire ignitions and provide data-driven guidance for PGE's Program. A technical overview of PGE's fire behavior modeling, a component of the wildfire risk approach, is provided in Appendix 9.

6.2 Updates to 2023 Wildfire Risk Mitigation Assessment

PGE aims to improve its Wildfire Risk Mitigation Assessment methodologies through engagement with external experts, as well as through internal controls and feedback loops across the organization.

PGE engages external agencies in the validation of existing variables and development of new variables and inputs for consideration in the risk assessment process. In 2022, this engagement included workshops and field site visits with Oregon Department of Forestry (ODF), U.S. Forest Service (USFS), and local fire agencies to look at fire agency response times to ignition events and assess how vegetation and access conditions influence fire growth potential. In addition, PGE hosted virtual technical working sessions with local fire districts (Clackamas Fire District, Tualatin Valley Fire District, Multnomah County Fire District) and ODF to learn about anticipated fire response times, watershed boundaries, and detection probabilities. These engagements and variables directly informed PGE's 2023 reassessment of the HFRZ geographical boundaries as described in Section 7 of the WMP.

Through an internal post-Fire Season lessons learned process, PGE refined its Wildfire Risk Mitigation Assessment methodologies by introducing new variables layered onto the existing assessment framework. For 2023, these additional variables include:

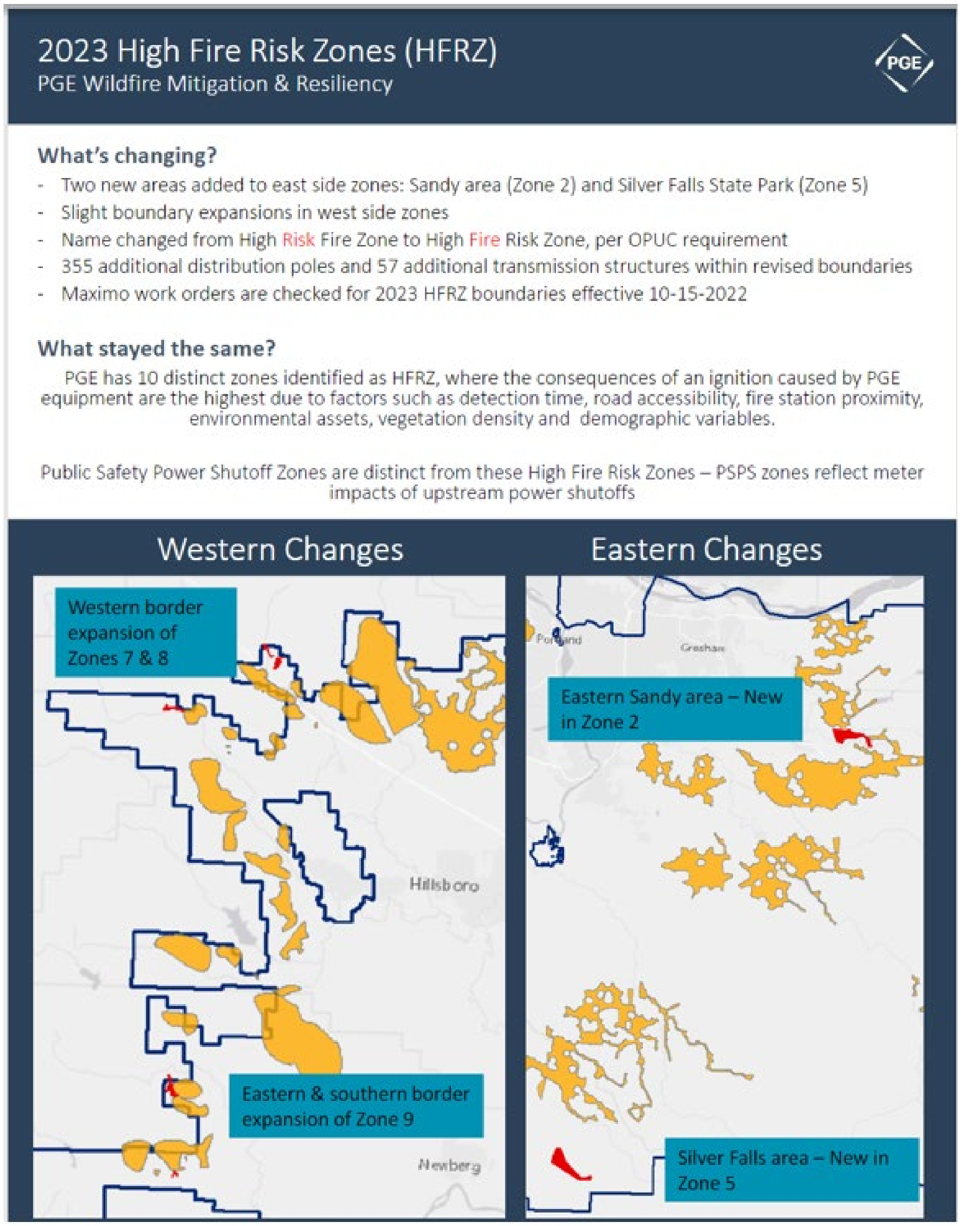
- Access/egress road density
- Detection probability

- Social vulnerability (including poverty, vehicle access, English as a second language considerations)
- Fire response time/proximity to emergency response (modelled at 10 and 15 minutes).

PGE continues to investigate improvements to data sets and analytical techniques to evolve its Wildfire Risk Mitigation Assessment methodologies and integrate fire risk into PGE's overall asset and risk management portfolios. Over the past two years, PGE has made the following changes to its baseline Wildfire Risk Mitigation Assessment:

- Began the development of a four-year wildfire risk mitigation roadmap, laying out planned mitigation activities through fiscal year 2025
- Increased the number of individual weather scenarios used to model baseline and seasonal wildfire risk (see the Wildfire Simulation Section of Appendix 9 for further details) to 216 scenarios, increasing model confidence
- Introduced new spatial variables to PGE's GIS-based wildfire risk mapping through virtual technical work sessions with local fire districts and the OPUC, including fire detection probability and estimated response time.

Figure 3: Geographic Differences Between PGE's 2022 and 2023 HFRZs



6.3 Wildfire Risk Categories

PGE's Wildfire Risk Mitigation Assessment methodologies consider baseline and seasonal wildfire risk, risk to residential areas served by PGE, and risks to generation facilities, substations, and powerlines owned by PGE. PGE uses these assessments to inform wildfire mitigation strategies that provide location-specific reliability and resiliency benefits. This holistic risk assessment approach helps PGE align specific mitigations to risk reduction areas, and to benefit a broad spectrum of regional stakeholders.

PGE seeks to align mitigation measures to risk across PGE's Program, from design and operational standards to construction practices, vegetation management, training, utility asset management, and capital investment.

6.3.1 Baseline Wildfire Risk

PGE calculates baseline equipment risk in terms of ignition probability (the annual likelihood that a given piece of equipment could cause a wildfire ignition given its type, age, condition, and location) and the consequences of ignition. These consequences evaluate how a wildfire ignited at a specific location may burn, as well as the potential magnitude of the damage it may cause. In most cases, probability values vary with age and condition of the asset, increasing as equipment ages.

6.3.2 Seasonal Wildfire Risk

Seasonal risk is integral to PGE's Wildfire Risk Mitigation Assessment. PGE's assessment of seasonal wildfire risk leverages the consequences modelled from the 216 fire weather scenarios referenced in Appendix 9. PGE also accounts for climate change variability in seasons by leveraging fuel ecology and wildfire studies for the Willamette Valley and Oregon[1]. For additional details regarding how PGE models seasonal wildfire risk, please refer to Appendix 9.

6.3.3 Risk to Residential Areas

PGE understands that ignition potential is not limited by HFRZ boundaries and models ignition points as a grid across the entire PGE footprint. PGE assesses risk to residential areas in the fire behavior models described in Appendix 9. PGE's modeling includes high-density locations as well as adjusted burn probabilities. A key factor in risk-informed decision-making is the recognition that detection probability and fire response time as a function of roads/access varies with population density.

6.3.4 Risk to PGE Equipment

PGE protects equipment and facilities within its HFRZs with established wildfire design and construction standards (e.g., replacement of wood poles with ductile iron as poles located in HFRZs that are damaged, replaced as part of non-wildfire projects, or reach end-of-life). In future iterations of PGE's Wildfire Risk Mitigation Assessment methodology, risk to PGE equipment will also be considered, as PGE adds the capability to assess which items of equipment are most likely to be damaged if a fire occurs in a given area. PGE is developing the tools required to factor information of this granularity into its Wildfire Risk Mitigation Assessment process.

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[1] Studies included in PGE's Wildfire Risk Mitigation Assessment include Climate Change Increases Risk of Extreme Rainfall Following Wildfire in the Western United States (Touma, Stevenson et al 2022); Changing Wildfire, Changing Forests: the Effects of Climate Change on Fire Regimes and Vegetation in the Pacific Northwest, USA (Halofsky, Peterson and Harvey, 2020); Impacts of Climate Change on Fire Regimes and Carbon Stocks of the U.S. Pacific Northwest (Rogers et al 2011).

6.3.5 Georisk

In addition to the risk categories above, PGE models geographic wildfire risk (georisk). Georisk represents wildfire risk due to vegetation encroachment on the conductor, and/or animal contact impacting the components of the structure. Georisk is distinct from asset risk, which is defined as risk due to failed equipment. This information has been integrated into PGE's Strategic Asset Management Structures Model (Structures Model), a component of PGE's Wildfire Risk Mitigation Assessment methodology that allows PGE to evaluate wildfire risk at a more precise level.

PGE inputs asset and georisk data in to the Pyrologix[2] fire physics engine to create simulated probabilistic models that assess fire risk by location, for both long-term planning and real-time decision support. As discussed in Section 6.2, PGE continues to refine variables in coordination with external agencies. This collaboration has led PGE to add new variables for consideration in its ongoing risk analysis processes. These variables include remote sensing both LiDAR and high-definition imagery, wildfire spread distributions and situational awareness variables.

The following table details the data sources for the various inputs PGE uses to assess georisk, as well as the proposed cadence of updates to these data sources.

[2] Pyrologix is a Missoula-based wildfire threat assessment research firm that provides utility wildfire risk assessment, hazard and risk assessment, stochastic wildfire simulation, fuel treatment prioritization, fuel inventory and management, and exposure analysis modeling and analysis services.

Table 1: Georisk Modeling Data Sources and Cadence of Updates

Data Sources	Inputs	Cadence of Updates
Wildfire Modeling	Fire Propagation and Fire Behavior	Annual review • Affirm/update Subject Matter Expert (SME) assumptions/updated failure data • Landfire (geospatial layering program) calibration through Pyrologix proprietary adjustments • Flame Height • Energy Release Component (ERC) (real-time through 72 hours out) • Fuel Moisture (measured at 1hr/10hr/100hr) (real time through 72 hours out) • Live Fuel Moisture Hourly/real time • Fire Response Time • Flame Intensity • Detection Probability
	Elevation Data	Annual/semi-annual review • Affirm/update SME assumptions/updated failure data • National Survey Data • USGS • LiDAR
	Meteorological Data	Annual/semi-annual review • National weather data • PGE weather stations (Real Time)
	Burn Probability	Annual review • Affirm/Update SME assumptions/updated failure data • Landfire calibration through Pyrologix proprietary adjustments

6.4 Risk Assessment Methodologies: Data Quality & Review Frequency

PGE Wildfire Risk Mitigation Assessment methodologies include multiple statistical models that use a variety of data sources to identify the areas of highest wildfire risk within PGE's service territory. PGE's methodology is consistent with the ISO-31000 Monitoring & Review structure, which provides internal controls to enhance confidence while still considering the dynamic nature of risk.

PGE's quality assurance and quality control (QA/QC) process for finalized Asset Risk models identifies the cadence of updates and required review tasks. Required QA/QC tasks include review and affirmation of existing or updated data, subject matter expert (SME) assumptions, review of mathematical formulas, and variance testing of updates to confirm that updates are reasonable.

The following table describes the cadence of updates for the inputs used in PGE's annual wildfire risk assessment process:

Table 2: Update Cadence for Key Modeling Inputs

Data Sources	Inputs	Cadence of Updates
Annual Probability of Asset Failure	Weibull failure curve parameters	Annual review • Affirm/update SME assumptions/updated failure data
	Health indexing	Annual review • Incorporate condition data (as available)
	Demographics from database	Periodic updates as data becomes available-GIS/Maximo
	GIS data for components on structures	Annual update to address reconfiguration/replacement
Annual Probability of Asset-Caused Ignition	Probability of equipment related outage is source of ignition	Annual review • Affirm/update SME assumptions
	Probability of equipment in violation of PGE patrol/inspection guidelines	Annual review • Incorporate inspection data (as available) • Incorporate updated SME assumptions
	Equipment multipliers	Annual review • Affirm/update SME assumptions
Ignition Data	Tracking PGE caused ignitions by failure mode/driver	Weekly review • Propagates into all wildfire risk processes

Data Sources	Inputs	Cadence of Updates
Intervention Costs	Capital cost estimates for wildfire mitigation	Annual review • Affirm/update SME assumptions
Consequence of Wildfire	The wildfire consequence model developed by Pyrologix identifies structures in burnable locations and estimates the expected consequence of a large fire (i.e., min 400 hectare) started at each location.	Periodic updates as required
Predictive Outage Model	Weather data & outages to understand outage correlation with storms/wind	Annual review Machine learning model will be continuously learning with annual updates

6.5 Wildfire Risk-Based Decision-Making

Climate change will continue to increase wildfire threats, requiring continual adaptation of asset management and other routine business practices. This challenging reality, combined with PGE's responsibility to maintain reliable electric service, requires a careful balance between often-competing interests and system requirements. As the complexity of this analysis increases with each passing year, PGE continues to be guided by the industry best practice of risk-informed decision-making (selecting mitigation projects based on estimated risk reduction value). As defined by Institute of Asset Management (IAM) criteria encompassed in International Organization for Standardization (ISO) 55000 standards, value is a function of lifecycle costs, performance and, ultimately, risk; Figure 4 illustrates this relationship.

Figure 4: The Value Equation

PGE factors in changing environmental conditions, impacts to the public and the environment, QA/QC on data quality, and new data sources to iterate and develop its wildfire risk mitigation strategy. PGE follows the ISO-31000 risk framework in evolving its Wildfire Risk Mitigation Assessment methodologies, and leverages both IAM and ISO concepts in value quantification to calculate Risk Spend Efficiency (RSE) across PGE's Program. This concept allows PGE to factor risk, lifecycle costs, and performance into a single process to provide guidance to understand and possibly estimate the effectiveness of mitigation measures. Lifecycle costs are represented in the equivalent annual cost (EAC) denominator.

Figure 5: The Risk Spend Efficiency Equation

Performance included in mitigation option, either consequence or relative probability

$$\text{RSE: } \frac{\text{(Risk of Problem – Risk after Mitigation)}}{\text{EAC of Mitigation}}$$

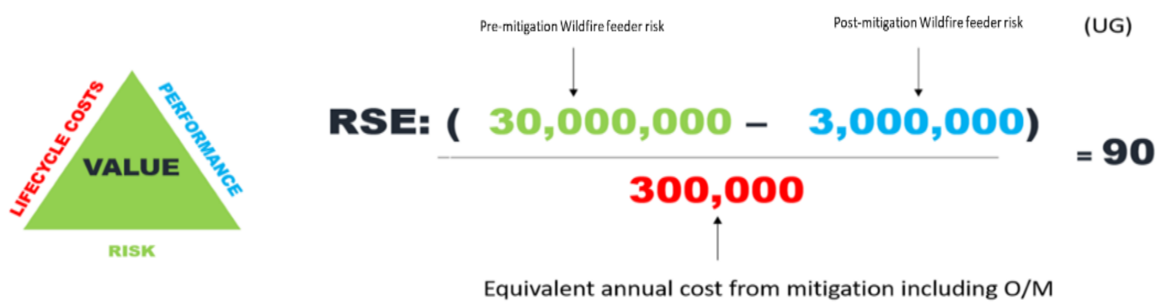
NOTE: RSE = Risk Spend Efficiency, **EAC**= Equivalent Annual Cost

PGE applies RSE concepts in assessing mitigation alternatives across a wide range of PGE programs, including PSPS, vegetation management, system hardening/capital investment, and operations. PGE is continually improving its RSE assessment approach for use in both long-term and real-time planning and analysis. The following example analyses illustrate how PGE uses RSE to inform the direction of its mitigation strategies.

The illustrative examples below show the mitigation alternatives assessment for a hypothetical feeder located within a PGE HFRZ, with specified wildfire risk characteristics (heat intensity, flame height, burn probability, detection probability, response time, egress limitations, etc.) not shown.

The assessments compare the RSE outcomes for one hypothetical mitigation measure (undergrounding) vs. another (reconductoring and installation of fire-safe fuses).

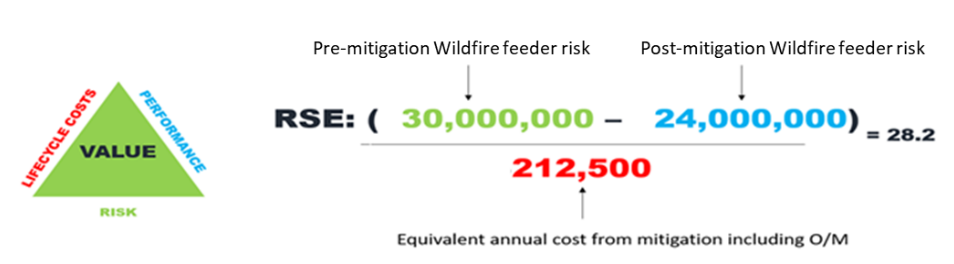
Figure 6: Illustrative Risk Spend Efficiency Assessment: Undergrounding



As this hypothetical example illustrates, in this case, undergrounding the line would yield an RSE coefficient of 90 (a 90:1 risk reduction per dollar of investment).

The following figure shows the RSE assessment for a second potential mitigation measure: reconductoring and installing fire-safe fuses.

Figure 7: Illustrative Risk Spend Efficiency Assessment: Reconductoring and Fire-Safe Fuses



In this hypothetical example, undergrounding the line (Example 1) would yield a higher RSE value—risk reduction per dollar of investment—than Example 2 (reconductoring the line and installing fire-safe fuses): an RSE value of 90:1 vs. 28:1.

RSEs directionally inform selection of wildfire mitigation options for inclusion in the mitigation strategies within the HFRZs. PGE's goal is to achieve the highest estimated risk reduction value per dollar invested. This RSE assessment approach is flexible enough to allow PGE to adjust the analytical variables to account for factors such as climate change, and to incorporate findings from its ODF, USFS, and local fire agency partnerships.

PGE uses data from internal as well as external benchmarking sources. For example, a statistical understanding of how failure modes and ignition drivers for covered conductor affect risk is critical to effectively evaluating the appropriate locations to install covered conductor. Through its participation in the International Wildfire Risk Mitigation Consortium (IWRMC), PGE has leveraged the experiences of industry peers to inform its fire detection probability analysis as well as decision-making around the most effective locations for use of covered wire.

The following sections provide detail about the ways in which PGE uses risk-based decision-making in specific areas of its Program:

6.5.1 Risk-Informed Decision Making for PSPS Events

PGE uses meteorological, outage data and predictive analytics to make risk-informed decisions regarding PSPS events, as well as curtailment decisions. Before and during Fire Season, PGE reviews regional NWS forecasts, fire activity briefings, fire potential forecasts, and data from PGE weather stations[3] strategically located throughout the service territory. PGE makes its weather station data publicly available via MesoWest, for anyone needing data to improve regional forecasting and the analysis of extreme weather events.

In 2023, PGE plans to improve its risk-informed decision-making through improved situational awareness capabilities. PGE plans to install 30 new remote automated weather stations (RAWS) and deploy its four mobile weather stations, as needed, within HFRZs. As RAWS are installed they will be incorporated into PGE situational awareness intake. Site selection for RAWS will take utility, meteorology, and stakeholder requirements into consideration to ensure optimal placement, as discussed in more detail in the Research and Development section of the WMP, in late 2022 PGE operationalized a prototype of a Storm Predictive Tool that will incorporate weather data from across PGE's service territory to better inform PGE's PSPS execution decision analysis. As additional RAWS come online, the data they record is intended to further refine the Predictive Outage model.

Please refer to Section 9.2, below, for addition detail regarding PGE's PSPS decision-making process.

6.5.2 Risk-Informed Decision Making and Mitigation Actions for Vegetation Management

PGE's vegetation management strategy includes both cyclical, routine inspections, and maintenance of the entire PGE distribution system. Additionally, PGE performs Advanced Wildfire Risk Reduction (AWRR) vegetation management activities in the HFRZs within PGE's service territory. Annual AWRR activities are guided by the designated boundaries of PGE's HFRZs, data from PGE's Remote Sensing Project (which uses LiDAR and hyperspectral imagery to monitor vegetation density and proximity to PGE assets), and annual vegetation surveys. AWRR crews follow program trim specifications, which include increased removal rates and enhanced vegetation control techniques, discussed in more detail in Section 11, Vegetation Management.

The evolution of PGE's Vegetation Management program also illustrates the influence of the Wildfire Risk Mitigation Assessment methodologies on PGE's wildfire-related investment decision-making. Originally dedicated to enhancing electrical reliability through compliance with OPUC safety and clearance requirements, PGE Vegetation Management has transitioned to a dual-track program, focused on increasing system reliability and decreasing the chance of infrastructure-caused ignitions.

[3] In 2022, PGE deployed 24 additional permanent weather stations and one temporary station to increase situational and conditional awareness and provide visibility within its HFRZs, bringing the number of permanent weather stations deployed within its service territory to 52.

Use of risk-based decision-making protocols has allowed PGE's Vegetation Management program to prioritize resources.

In much the same way, cross-organizational access to data from PGE's Remote Sensing Project data allows working groups across the company to plan and implement mitigation activities using a consistent set of data and analysis, with benefits shared across PGE workflows, including design and vegetation maintenance. PGE's GIS, Strategic Assessment Management, WM&R and Vegetation Management organizations all use LiDAR data, both independently and cooperatively, to benefit operational efficiency.

6.5.3 Risk-Informed Decision Making and Mitigation Actions for System Hardening

PGE continues to leverage its SAM Structures Model and Fire-Safe Construction Standard to harden the transmission and distribution (T&D) system within its HFRZs. PGE's system hardening activities are designed to accomplish three goals:

- Reduce the risk of potential wildfire ignition caused by PGE facilities through the use of ductile iron poles, fiberglass crossarms, covered wire, transformers, and conductor undergrounding
- Reduce the impacts of a wildfire on PGE's assets by installing system hardening technologies (fire mesh, ductile iron poles, fiberglass crossarms, conductor undergrounding)
- Protect utility infrastructure during potentially disruptive natural and human-caused disasters, strengthening PGE's ability to maintain and quickly restore reliable electrical service to support disaster relief and public safety.

In working towards these goals, PGE will deploy additional reliability and wildfire risk mitigation improvements within the HFRZs. PGE is guided by its annually updated Fire-Safe Construction Standard in executing equipment replacements in HFRZs. As specified in the Fire-Safe Construction Standard, the company will evaluate the following assets for replacement, installation, or implementation, when warranted:

- Avian-safe framing and phase covers
- Replacement of wood structures with nonflammable structures (e.g.: ductile iron poles, fiberglass crossarms)
- Polymer cutouts and cutout covers
- Aging conductors in HFRZs
- Tree wire, an insulated overhead conductor designed to reduce service interruptions, which also reduces the potential for the conductor to become an ignition source
- Overhead to underground conversions on specific feeders with key wildfire response variables including fire response/detection probability and egress
- Fuse replacement with fire-safe fuses and/or ELF (non-expulsion) fuses to eliminate a potential ignition source
- Reclosers and switching devices to increase operational flexibility and minimize customer impacts through the application of wildfire operational settings

6.5.4 Risk-Informed Decision Making and Mitigation Actions for Capital Investments

PGE uses the SAM Structural Model and the RSE methodology discussed in Section 6.5, Wildfire Risk-Based Decision-Making, in assessing project alternatives and prioritization of wildfire risk mitigation investments. Based on the outcomes of this analysis, PGE's multi-year wildfire capital investment strategy ranks system hardening and situational awareness projects as the highest-value risk mitigation per dollar of investment to inform prioritization of PGE's capital budget. Please refer to Section 12, Wildfire Program Costs, for detailed information regarding year-to-year actual and planned WM&R O&M and capital expenditures.

For example, undergrounding and reconductoring feeders and distribution lines is one of the most effective ways to shield PGE equipment from vegetation and animal contacts that could lead to wildfire ignition. Table 3, below, shows the planned undergrounding and reconductoring investments currently included in PGE's 2023 wildfire capital investment strategy.

PGE is revising its 2023–2026 wildfire capital investment strategy, which distributes planned capital spending among multiple asset and mitigation classes in alignment with the Wildfire Risk Mitigation Assessment of wildfire risk change over time. The goal of this effort is to create an optimized multi-year investment framework to implement separate but interrelated mitigation strategies, based on a risk profile that incorporates a broad spectrum of wildfire risk drivers.

PGE is consistently evaluating its long-term investment strategy in response to R&D findings, risk modeling and industry experience, and will continue to optimize its investment strategy for wildfire risk mitigation based on the best available information and analysis. Tables 3 and 4, below, reflect PGE's best estimates of planned investments and timelines at the time this document was submitted; however, PGE recognizes that factors outside of the company's control or to customer advantage may require adjustments to this schedule of activities. Planned line-miles per year are targets or estimates, which may be adjusted based on a wide variety of factors aimed to reduce wildfire risk and increase system resiliency.

PGE's portfolio of planned capital investment projects offers co-benefits in addition to their wildfire mitigation value; for example, many of the PGE feeders with the highest Customers Experiencing Multiple Interruptions (CEMI) values[4] (feeders that experience multiple outages per year) are designated for hardening under this strategy. By aligning its strategy to prioritize both wildfire mitigation and CEMI, PGE is investing in outcomes that offer regional benefit beyond wildfire hardening. System hardening projects on Tribal lands, and within culturally or environmentally sensitive areas, provide the co-benefits of improved cultural resource and environmental protection.

Ultimately, upon successful completion of the measures referenced above, these system hardening investments will reduce PGE's wildfire risk while shrinking the geographic boundaries of three existing PGE HFRZs—as line-miles of PGE infrastructure are hardened over the next several years, PGE will no longer need to de-energize those circuits to prevent potential ignitions during PSPS events. PGE plans

[4] CEMI is an industry-standard metric of system reliability

to estimate these risk reduction values with a combination of volumetric mileage in a mitigated state as well as number of customer meters impacted by PSPS events.

PGE will also estimate non-wildfire-related resiliency benefits from these investments—for example, increased protection from wind/ice storm damage—using traditional asset management expected risk and net economic benefit ratios. The following tables show PGE's planned undergrounding/reconductoring projects and situational awareness/programmatic investments, by region, for 2023:

Table 3: Planned Wildfire Undergrounding/Reconductoring Investments (in Line-Miles), 2023

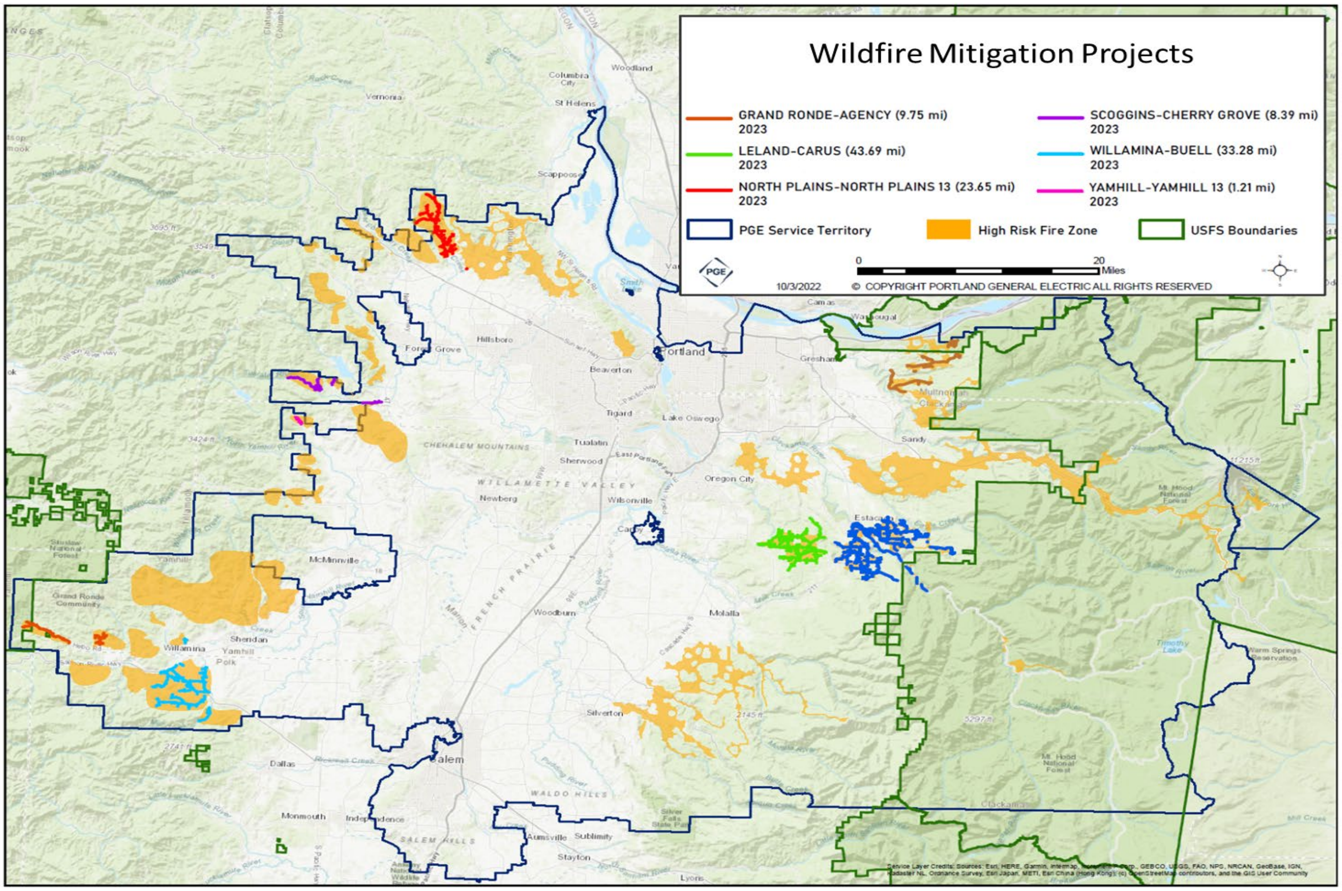
UG/RECON	2023
Grande Ronde-Agency (UG)	9.75
Scoggins-Cherry Grove (UG)	8.39
Yamhill-Yamhill 13 (UG)	0.6
North Plains (RC)	8.0
Leland-Carus (RC)	14.56
Willamina-Buell (UG)	11.09
TOTAL	**44.39**

Table 4: Planned Situational Awareness/Programmatic Investments, 2023

Programmatic	2023
AI-Equipped UHD Cameras	6
Weather Stations	30
Reclosers	50
Fire-Safe Fuses	600
Early Fault Detection (EFD)[5]	1 feeder

[5] Early Fault Detection is a technology that uses sensors to detect anomalies on the feeder in real time, allowing PGE to intervene (replace or repair) the affected component(s) prior to a failure that could cause an ignition.

Figure 8: Planned PGE Wildfire Mitigation Investments 2023



6.5.5 Risk-Informed Decision-Making and Mitigation Actions for Operations

PGE relies on a wide variety of weather and fuel models, as well as human analysis, to obtain the granularity of information required to accurately forecast and model hazardous fire weather conditions. The goal is to use these models to forecast potential hazardous fire weather conditions 7-10 days in advance. These models can provide decision-makers with a detailed understanding of the uncertainties and range of outcomes possible for a given weather pattern. Operational procedures within the HFRZs during the Fire Season are discussed in further detail in Section 8.2, System Operations During Fire Season.

In 2023, PGE will conduct further model testing and validation to assess the Storm Predictive Tool's ability to incorporate more granular and sophisticated inputs to better inform PGE's PSPS execution decision analysis and improve system alarming. For additional details regarding the Storm Predictive Tool, please refer to Section 15.4, below.

This tool should improve PGE's ability to predict potential equipment outages based on forecasted and real-time meteorological data. Once integrated with other PGE capabilities, the Storm Predictive Tool is intended to offer co-benefits to PGE's Utility Asset Management program, including increased spare equipment ordering efficiency, as well as improved spare equipment mobilization and operational standards and practices.

6.5.6 Risk-Informed Decision Making for Prioritized Opportunistic Interventions

Generally, when repairs are needed on an asset and the cost of the repair is higher than the value of the asset, the asset will be evaluated for replacement. Once crews are mobilized, there may also be reliability and economic benefits to proactive asset replacement, particularly within HFRZs. Whenever possible, PGE assesses the cost/benefit of proactive asset replacement during planned improvement/maintenance activities on other nearby assets. This approach helps PGE maintain reliable electric service and increase cost efficiency.

PGE prioritizes capital investments and maintenance activities that provide highest benefits to the system including reduced outage duration, improved asset survival and other impacts to infrastructure beyond wildfire mitigation. This multi-dimensional view allows PGE to achieve the best value risk reduction per dollar of investment.

7. High Fire Risk Zones (HFRZs)

PGE has identified areas of its service territory where vegetation, terrain, meteorology, population density and the wildland-urban interface (WUI) increase the risks associated with utility-caused wildfire ignition. For the purposes of this WMP, PGE refers to these areas as High Fire Risk Zones (HFRZs). PGE may choose to implement a proactive PSPS within a given HFRZ during periods of extreme weather wildfire threat. For 2023, PGE has identified the same 10 HFRZs as in 2022, with minor refinements, modifying the geographic boundaries of some zones and adding a total of 355 distribution poles and 57 transmission structures to the areas potentially impacted by PSPS events (see Figure 10 below for details):

HFRZ 1: Mt. Hood Corridor/Foothills
HFRZ 2: Columbia River Gorge
HFRZ 3: Oregon City
HFRZ 4: Estacada
HFRZ 5: Scott's Mills
HFRZ 6: Portland West Hills
HFRZ 7: Tualatin Mountains
HFRZ 8: North West Hills
HFRZ 9: Central West Hills
HFRZ 10: Southern West Hills

PGE relied on the ISO-31000 wildfire risk analysis framework for the 2023 HFRZ Assessment. For this assessment PGE incorporated new variables and refined boundary conditions to improve its understanding of:

- Wildfire risk
- Location based wildfire intensity and behavior
- Climate change impact projections
- Fire behavior and consequences

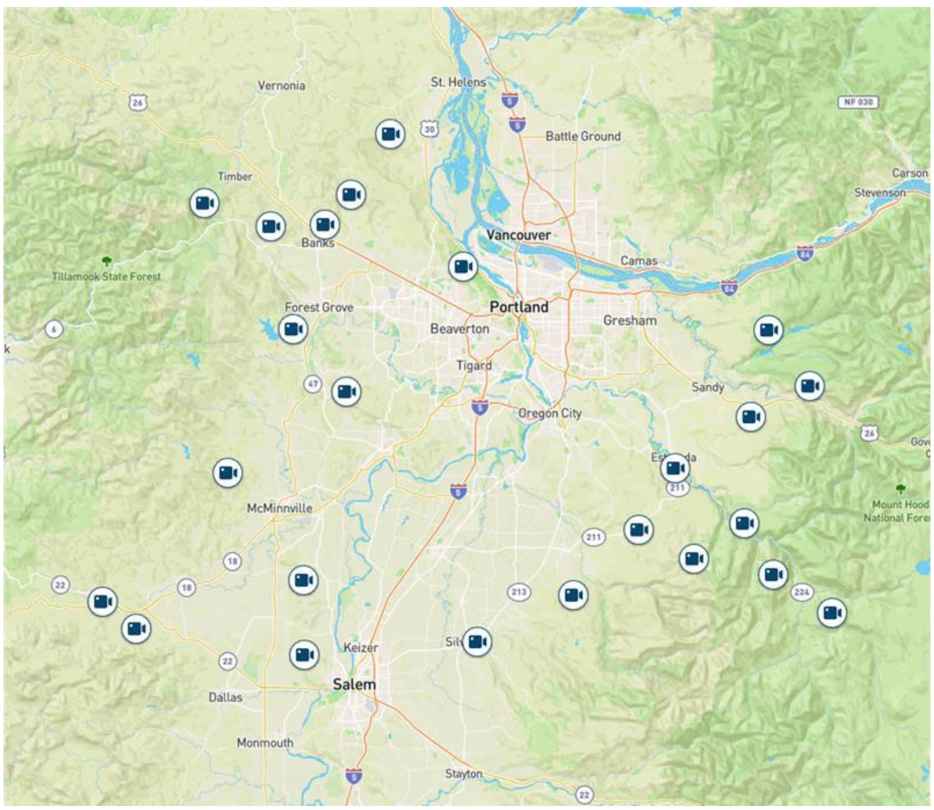
PGE's Wildfire Risk Assessment factors in the likelihood that a given PGE asset could become an ignition source, as well as the likelihood that such an ignition could spread into a large, uncontrolled fire. Additional analytical factors include vegetation density, fuels dryness, the potential for extreme weather conditions, probability of mechanical control, fire response time, detection probability and the presence of structures and other infrastructure.

In conducting the risk assessment, PGE ran thousands of scenarios in a Monte Carlo simulation to identify the areas of the PGE service territory where the risks associated with a utility-caused ignition are highest. The results of this modeling provided the basis for PGE's 2023 HFRZ analysis.

7.1 Enhanced Monitoring and Technology in HFRZs

In a partnership with the Electric Power Research Institute (EPRI), PGE installed a network of connected, intelligent fire detection cameras equipped with artificial intelligence (AI) within its HFRZs. These ultra-high-definition camera systems give PGE a 360-degree fire detection triangulation capability across its service territory, accurate to within +/- 100 yards. The Pano AI platform's machine learning algorithms automate fire detection, awareness, and notifications, helping PGE expand and improve regional fire detection resources. Under its 2023 Wildfire Capital Investment Strategy, PGE is planning to install six additional AI-equipped UHD cameras within the HFRZs (refer to Figure 9 for details regarding camera locations). For additional details on PGE's Wildfire Capital Investment Strategy, please refer to Section 12, Wildfire Program Costs.

Figure 9: 2023 PGE Pano AI Camera Locations



These camera systems are part of a larger situational awareness strategy in which PGE coordinates with federal, state, Tribal, and local fire agencies, fire management officers, and district foresters, as well as private landowners. In 2023, PGE will continue to seek ways to share access to this information with its Public Safety Partners, 30 of which currently have access to the camera network and notifications:

- Canby Fire District
- Forest Grove Fire & Rescue
- Gresham Fire & Emergency Services
- Lake Oswego Fire Department
- City of Portland Fire & Rescue
- City of Portland Water Bureau
- Clackamas Fire District #1
- Clackamas County Fire Defense Board
- The Confederated Tribes of Grande Ronde Emergency Services
- Estacada Rural Fire Protection District
- Gaston Fire District
- Hillsboro Fire & Rescue
- Hoodland Fire District
- Life Flight Network
- Marion County Fire Defense Board
- Marion Area Multi Agency Emergency Telecommunications (METCOM)
- Mt. Angel Fire District
- Multnomah County Fire Defense Board
- Oregon Department of Forestry
- Oregon State Police
- Polk County Fire Defense Board
- Sandy Fire District
- State of Oregon
- T-Mobile
- Tualatin Valley Fire & Rescue
- USFS – Mt. Hood District
- Washington County Fire Defense Board
- Washington County Consolidated Communications Agency (WCCCA)
- Yamhill County Fire Defense Board
- Yamhill Communications Agency (YCOM)

To illustrate the potential value of this technology, at 1525 on July 14, PGE's Bald Peak Pano AI camera notified users that it had detected smoke in a rural area in the western part of PGE's service territory. At 1625, PGE's High Compromise camera issued a second "detected smoke" notification and triangulated the smoke's location 6.8 miles away. The Pano AI system's initial detection and notification was 104 minutes before the regional fire reporting service issued a potential wildland fire alert, and 140 minutes before emergency services personnel were dispatched to the fire. ODF and other federal, Tribal, state, and local fire departments as well as land management agencies have provided feedback that the early detection information and triangulation accuracy obtained through PGE's Pano AI camera network is making a difference in crew deployment optimization and initial attack speed.

The following figures show PGE's 2023 HFRZs, and changes in HFRZ boundaries from 2022 to 2023.

Figure 10: PGE HFRZs 2023 vs. 2022

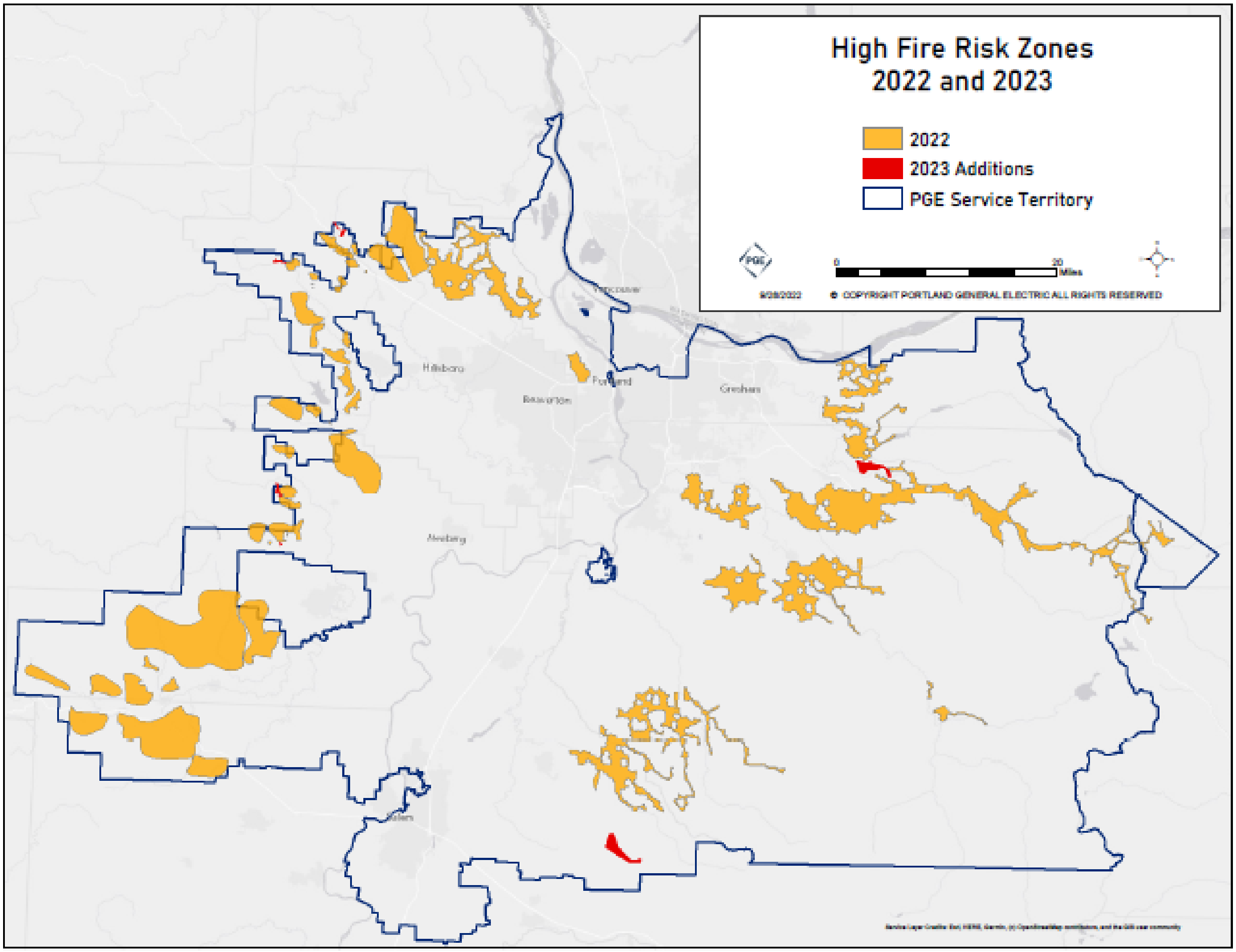


Figure 11: 2023 PGE HFRZs

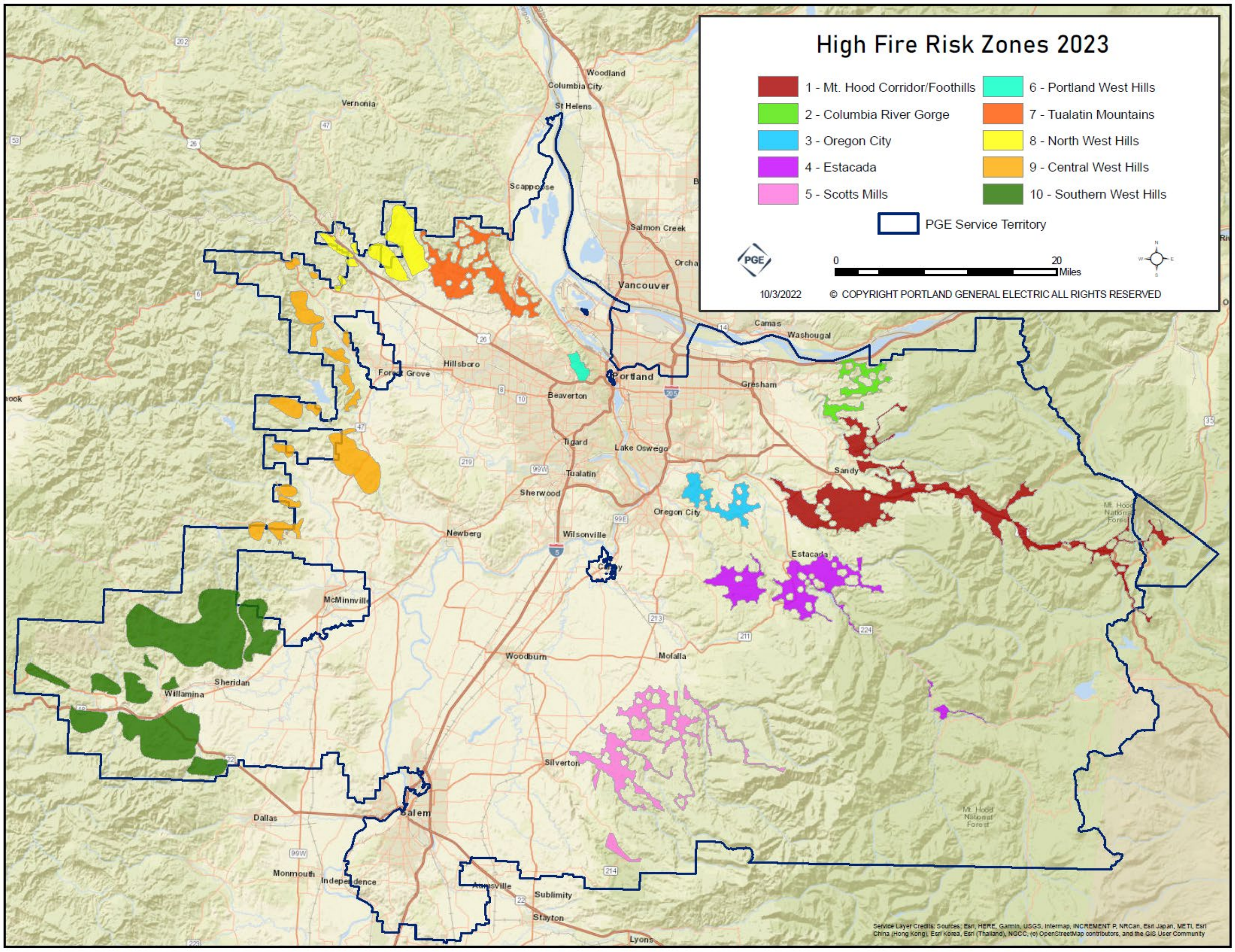


Table 5: Changes in Distribution Line-Miles Within PGE's HFRZs, 2022 vs 2023

	DISTRIBUTION LINE MILES		T&D POLES		CUSTOMERS (METERS)	
HFRZ	**2022**	**2023 (NET CHANGE)**	**2022**	**2023 (NET CHANGE)**	**2022**	**2023 (NET CHANGE)**
Zone 1	244.8	249.7 (+4.9)	7,780	7,930 (+110)	9,464	9.513 (+49)
Zone 2	24.7	24.7 (0.0)	710	710 (0)	456	456 (0)
Zone 3	47.4	47.4 (0.0)	1,268	1,268 (0)	1,743	1,743 (0)
Zone 4	138.5	138.5 (0.0)	3,727	3,726 (-1)	2,655	2,652 (-3)
Zone 5	142.7	150.7 (+8.0)	3,274	3,442 (+168)	1,927	2,000 (+73)
Zone 6	15.0	15.0 (0.0)	702	702 (0)	961	960 (-1)
Zone 7	91.6	91.6 (0.0)	2,182	2,182 (0)	1,525	1,524 (-1)
Zone 8	41.4	43.1 (+1.7)	1,025	1,068 (+43)	731	762 (+31)
Zone 9	75.4	78.4 (+3.0)	1,742	1,820 (+78)	1,005	1,049 (+44)
Zone 10	134.9	133.9 (-1.0)	3,091	3,085 (-6)	1,711	1,710 (-1)

8. Operating Protocols

8.1 Fire Season

PGE declares its own Fire Season based on a variety of factors, such as current and forecasted weather, drought status/timing and intensity, fuel availability and flammability, agency posture, and regional fire activity. PGE bases its decisions on data and information from multiple sources and considers State and Tribal Fire Season declarations within its service territory. The annual Fire Season declaration initiates a series of PGE operational changes.

PGE's Fire Season declaration:

- Changes how the company operates the PGE system, initiating fire-season-specific settings within parts of the grid, including disabling reclosing/testing capabilities, where applicable
- Initiates Fire Season operational work practices in the field
- Activates internal 24x7 Wildfire Threat Alert Notifications (Threat Alerts). Threat Alerts are a GIS-triggered, near-real-time analytical tool that alerts PGE when:
    - Any fire incident has been confirmed by the Integrated Reporting of Wildland-Fire Information (IRWIN) service within one mile of a PGE facility in the last hour (five miles for PGE Parks)
    - A Red Flag Warning has been issued covering an area within one mile of a PGE facility within the last 24 hours (five miles for PGE Parks), and
    - A confirmed fire perimeter is updated by the National Interagency Fire Center (NIFC) within one mile of a PGE facility in the last hour (five miles for PGE Parks) in the event of an expanding wildfire.

8.2 System Operations During Fire Season

Once it declares the start of Fire Season, PGE implements operational changes to reduce the risk that PGE infrastructure and operations could become ignition sources. For non-Supervisory Control and Data Acquisition (SCADA) distribution reclosing devices in PGE's HFRZs, these system changes include manually blocking the automatic test-energization of circuits following temporary faults, such as momentary tree branch contacts and lightning strikes with no damage. SCADA distribution reclosing devices are operated as shown in Table 6. Prior to re-energizing, PGE will patrol the downstream circuit to verify that the cause of the fault has been cleared.

PGE may also change settings outside of Fire Season, when the risk of wildfire danger is elevated, or when a Red Flag Warning is in effect. In these instances, PGE will proactively block automatic reclosing on SCADA-controlled devices within PGE's HFRZs.

PGE annually reviews and updates settings for protection and control devices located within PGE HFRZs. In 2023, PGE will continue to implement circuit breaker and recloser protection to minimize fault energy and reduce the risk of utility-caused ignitions during Fire Season.

Additionally, the distribution feeder breakers servicing PGE's HFRZs (those equipped with relays and SCADA) can be set one of three modes: Normal, Fire Season, or Red Flag. Those 13 kV feeders that do not have relays utilize the electronic reclosers' necessary protection settings: Normal, Wildfire, and Red Flag mode.

The tables below show the distribution system operations inside and outside of Fire Season that provide the necessary protection settings for Normal, Fire Season, and Red Flag modes.

Table 6: Distribution System Operations In and Out of Fire Season

Mode	Description	Reason
Normal	The feeder breaker will have two attempts of reclosing (an automatic test energization of the circuit following a fault event) and instantaneous (relay trips instantly when a fault occurs, with no preprogrammed delay)	Maximize reliability
Fire Season	The feeder breaker or electronic recloser will have one attempt of reclosing and trip on definite time instantaneous (a programmed delay before the relay trips).	Minimize risk of ignition
Red Flag Warning (during Fire Season)	The feeder breaker or electronic recloser trips on definite time instantaneous and reclosing is blocked.	Minimize risk of ignition

NOTE: Transmission lines located east of the Cascades that traverse PGE's HFRZs do not have specialized wildfire protective modes. As a result, they are placed in the most conservative mode of operation during PGE's declared Fire Season. Transmission lines that are not equipped with SCADA-enabled reclosing will be blocked from reclosing throughout Fire Season. Transmission lines that are equipped with SCADA-enabled reclosing will remain in automatic mode when PGE declares Fire Season. If one of these lines relays and recloses, reclosing will be blocked via SCADA and the line will be patrolled.

Table 7: Pelton & Round Butte Transmission System Operations In and Out of Fire Season

Mode	Description	Reason
Normal	Two recloses at Pelton, one reclosure at Round Butte	Maximize reliability
Fire Season & Red Flag Warning	Reclosing is blocked—reclosers open and lock out without testing the circuit by auto-reclosing.	Minimize risk of ignition

8.3 Preparedness and Training

Prior to Fire Season, PGE provides annual wildfire training to keep employees who will be working in the field during Fire Season safe. This includes non-field personnel that may go into the field on an as-needed basis. Participants receive training, either through computer-based training or a hands-on curriculum covering the use of required fire suppression tools and equipment during field deployments. Contractors who perform work in the field on behalf of PGE must also satisfy this training requirement and carry fire suppression tools and equipment. Training topics for 2023 focus on employee and contractor safety and include (but are not limited to):

- How fuels, weather, and topography impact the ignition and spread of wildfires
- What a fire weather zone forecast is, and how to interpret key factors and validate them in the field
- The suppression tools and equipment PGE, and those acting on behalf of PGE, are required to carry
- Basic suppression tactics for low-intensity ground and surface fires, and
- How to identify lookouts, communications, escape routes, and safety zones (LCES), and how this critical life safety acronym applies to all PGE Fire Season operations.

8.4 Event Response & Management

PGE closely monitors active wildfires in or near its distribution service territory and generation asset areas in Oregon and Washington. As an incident expands in size and complexity, PGE will contact the appropriate agency Incident Management Team (IMT) and may offer to embed PGE representatives at the incident command post. PGE representatives are delegated authority to make decisions that align with Corporate Incident Management Team (CIMT) and company leadership direction on PGE's behalf. The goal of this strategy is to enhance interoperability, share information, and promote collaboration with utility peers, Public Safety Partners, and state, Tribal, and local emergency managers to achieve shared objectives to serve the community and affected customers.

During a PSPS event, PGE's CIMT will follow established procedures and protocols to manage the event—see Section 9, Operations During PSPS Events, for more details. Under certain circumstances, the CIMT may execute additional de-energizations known as Preventative Outage Areas (POAs)to protect against risk of ignition or to protect life and safety. POAs are executed as needed based upon critical circumstances such as emerging meteorological events, system topology conditions, and/or interactions with PGE's Public Safety Partners during PSPS events. POAs are outside of PGE-defined PSPS Areas and do not receive pre-fire season communications. CRCs will also not be deployed for POA events.

POAs are executed under PGE's protocols for emergent de-energizations, which can occur during and outside of Fire Season. PGE personnel on-site also have authority to de-energize portions of the distribution system without requesting permission from or notifying PGE management (for example: to de-energize a downed power line). In addition, first responders may request an emergent de-energization from PGE via 911.

PGE personnel on-site have the authority to de-energize that portion of the distribution system without requesting permission from or notifying PGE management (for example: to de-energize a downed power line). In addition, first responders may request an emergent de-energization from PGE via 911.

9. Operations During PSPS Events

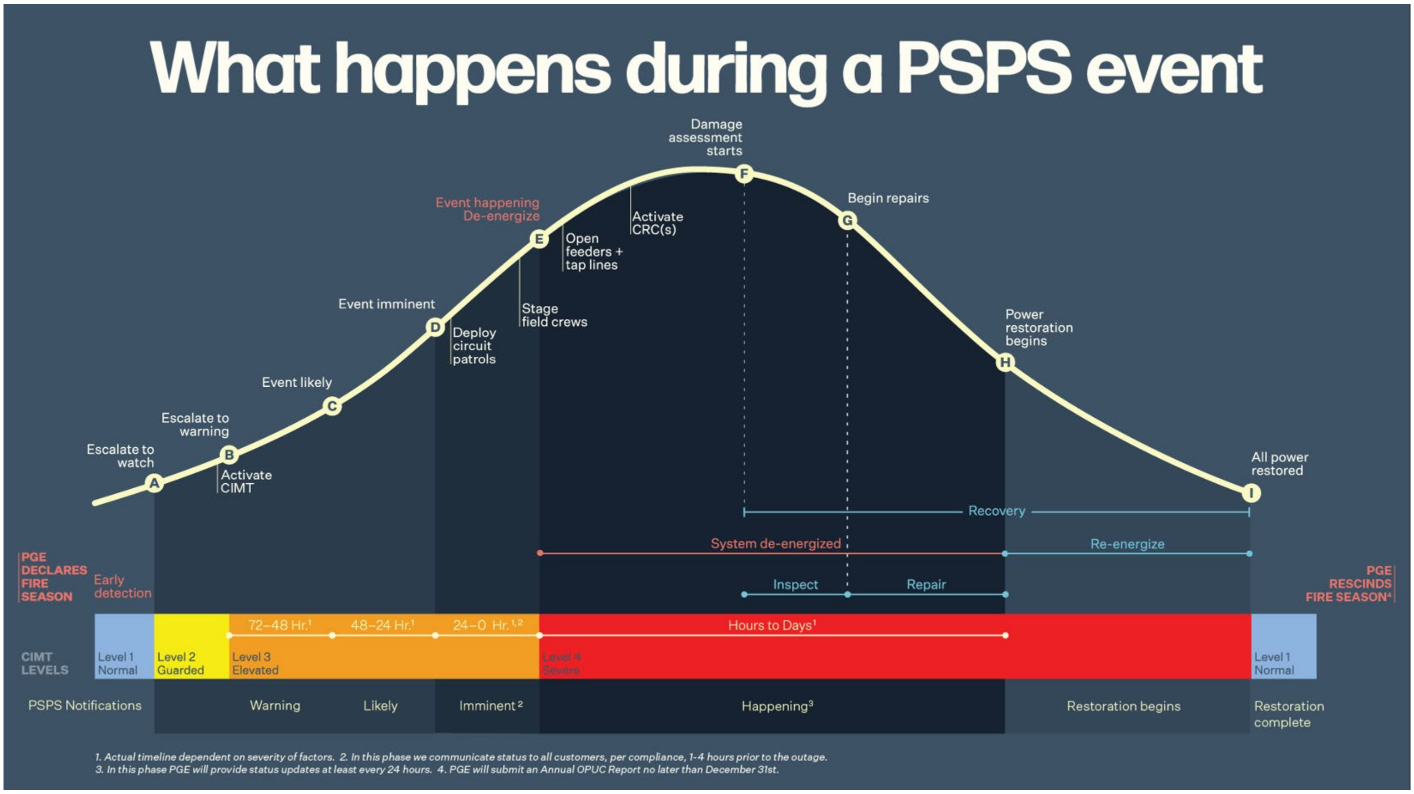
As discussed in Section 6.5.1, Risk-Based Decision-Making for PSPS Events, PGE uses meteorological and outage data and predictive analytics to decide whether to execute a PSPS event. This section provides a high-level overview of the escalating levels of a PSPS event, and the actions taken within each level. PGE maintains detailed, annually updated operational plans and protocols for PSPS events in internal documentation libraries.

The PSPS Process bell curve (Figure 12, below) correlates the various incident levels defined in internal PGE emergency operations plans to illustrate typical operations during the various phases of a PSPS event. It is intended to provide a point of reference only, as PGE may adjust operations during a PSPS event based on real-time conditions.

During an event, information including location, de-energization estimates, and estimated restoration times (ERTs) for each impacted PSPS Area can be found on PGE'S Wildfire Outages and PSPS webpage. PGE's website has the bandwidth capable of handling web traffic surges expected during PSPS events, and all web-based PSPS information will be easily readable and accessible on mobile devices.

During the 2023 Fire Season, PGE will provide multiple options to allow Public Safety Partners to access real-time GIS information pertaining to PSPS outages. These options include a link to PGE's public PSPS web layer service and an ArcGIS Online (AGOL) web map containing PSPS information as required by OAR 860-300-0060. Both the PSPS web layer service and AGOL web maps are updated simultaneously with the PSPS Area map found on PGE'S Wildfire Outages & PSPS page. PGE will continue to evaluate the customer experience with these tools and look for ways to improve that overall experience in the 2023 Fire Season.

Figure 12: PSPS Process Bell Curve

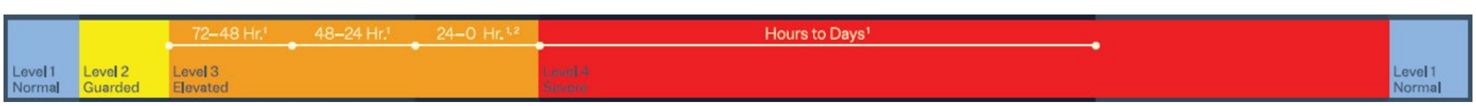


9.1 Protocols for De-Energization of Power Lines and Power System Operations During PSPS Events

As a last-resort safety measure to protect people, property, and public areas, PGE will proactively turn off power within one or more PSPS Areas when conditions threaten the ability to safely operate the grid. When PSPS events are declared, PGE takes steps to keep customers and stakeholders well-informed and strives to mitigate customer impacts by limiting the duration of the outage, as much as conditions allow.

9.2 Levels of a PSPS Event

If PGE makes the decision to execute a PSPS event, the order of operation generally follows the PSPS Process Bell Curve (Figure 12, above). PGE will adapt actual PSPS event operations as required to address evolving, dynamic, and unpredictable circumstances.



Level 1: Normal

Once Fire Season has been declared, under **Level 1: Normal** conditions, PGE closely monitors and communicates regional weather and wildfire situation/status to operational leadership. Through real-time situational awareness monitoring, PGE can tailor operational and system changes during Fire Season, thereby increasing safety and operational efficiency.

Year-round, PGE conducts a Daily (M-F) Operations Call. Should weather or other related events warrant communications outside the normal schedule, PGE may decide to convene the Daily Operations Call on weekends or holidays. During Fire Season, this daily briefing includes, but is not limited to:

- Fire weather forecasts and fire potential specific to PGE's service territory
- Reporting of National Weather Service (NWS)-issued Fire Weather Watches and/or Red Flag Warnings
- Summary of current regional fire activity

Additionally, PGE closely monitors changing or deteriorating conditions, regularly communicating critical updates to affected business units. To assist with this, PGE maintains working relationships with fire agencies, fire management officers, district foresters and dispatch centers at the federal, state, Tribal and local levels, including the Portland office of the NWS. These partnerships provide PGE with specific, granular situational awareness, assistance with forecast modeling validation, fire suppression resource pre-positioning, and activity/growth updates for fires in proximity to PGE assets.

Level 2: Guarded

If PGE determines that current or predicted fire risk conditions warrant an escalation in planning and coordination, PGE shifts from **Level 1: Normal** to **Level 2: Guarded**, which represents a PSPS Watch posture. When this occurs, PGE will activate the PSPS Assessment Team (PAT) to monitor conditions and prepare the company to initiate the next phase of PSPS plans and procedures, if necessary. PGE also issues a preliminary notification to internal stakeholders and ESF-12 OPUC Safety Staff that PGE has moved to **Level 2: Guarded** status. Following the decision to issue a **Level 2: Guarded** notification, PGE will place the company's full CIMT on standby and build out its duty roster.

Level 3: Elevated

PGE's decision to escalate from **Level 2: Guarded** to **Level 3: Elevated** status is predicated on conditions on the ground, pace of onset of weather conditions and risk tolerance at the time. Once the decision is made to proceed to **Level 3: Elevated**, PGE will fully activate the CIMT.

Level 3: Elevated is divided into three sequential, time-boxed phases, each representing an escalated state of readiness. To the extent practicable, PGE will adhere to the following notification timeline in advance of a PSPS event:

- **PSPS Warning**: 72-48 hours prior to de-energization
- **PSPS Likely**: 48-24 hours prior to de-energization
- **PSPS Imminent**: 4-1 hours prior to de-energization

Preparation for De-Energization

During the **Level 3: Elevated** phase of the potential PSPS event, PGE closely monitors fire potential indicators, situation, and status. The CIMT develops Incident Action Plans (IAPs) for each operational period (or as directed by the CIMT's IC), including situation-specific tactics and detailed instructions for field and support personnel—for example, pre-positioning of Pre-PSPS Circuit Patrol personnel and Community Resource Centers (CRCs) in applicable PSPS Areas. Immediately prior to de-energization, PGE resources in the field move into their "Get Set" positions or designated staging areas until execution of de-energization begins.

PGE will continue to monitor fire weather conditions throughout the **Level 3: Elevated** phase. When threshold conditions indicate that a PSPS is imminent and the CIMT's Situational Unit and IC have determined that escalating to **Level 4: Severe** (Event Happening stage) is appropriate, they will request de-energization approval for the appropriate PSPS areas(s) from the Officer-In-Charge (OIC).

Level 4: Severe: (Event Happening)

Transitioning from **Level 3: Elevated** to **Level 4: Severe**, is triggered by the decision to de-energize the PSPS Area(s). Immediately thereafter, field resources are given the "Go" signal to open feeder and tap line breakers and activate CRCs. PGE will communicate the start of the de-energization, as indicated in Table 8, below.

Community Resource Centers (CRCs)

During PSPS events, PGE may establish CRCs in selected areas to provide critical restoration information, including updates and real-time information, to customers impacted by the outage(s). The CRCs also provide customers with electronic and/or medical device charging, internet access, and clean water and ice, to offset some of the impacts associated with PSPS de-energization.

PGE has identified multiple potential locations for CRCs within or near each PSPS Area, to provide the flexibility to select the location that best suits customers' needs based on event specifics. PGE may or may not activate CRCs at all pre-designated locations during a particular PSPS event—depending on the nature of the event, some CRC locations may not be needed, or it may also be possible to serve multiple PSPS-impacted areas from a common CRC location. Pre-identifying multiple CRC locations within each PSPS Area also gives PGE options if mandatory evacuations require the relocation of a CRC. PGE's goal is to locate CRCs as near as possible to the areas impacted by the de-energization, although specific circumstances may make this impractical.

PGE's decision-making process for the potential deployment of CRCs begins during the **Level 3: Elevated** PSPS Likely phase. At this phase, PGE selects the specific CRC location(s) and sets hours of operation. Whenever possible, PGE will work with community partners to make CRC resources available to impacted customers; in some instances (for example, when resources are being provided by a County, Red Cross, or other entity, when multiple PSPS Areas are served by a single CRC, or when safety concerns preclude PGE's ability to site a particular CRC), PGE may not establish a CRC in an impacted PSPS Area. PGE will notify Public Safety Partners and Adjacent Public Safety partners as soon as CRC location and activation schedules have been confirmed. PGE will make efforts to have CRCs operational within 24 hours of de-energization, and to keep these locations operational as long as they are of benefit to customers.

Figure 13: September 2022 PGE CRC Volunteers

9.3 Communications Requirements During PSPS Events

Beginning at the **Level 3: Elevated** phase, to the extent practicable, PGE will initiate a methodical sequence of pre-event PSPS notifications and subsequent updates, delivered in 24-hour intervals, that progress from each of the three **Level 3: Elevated** phases (Warning, Likely, Imminent) through the **Level 4: Severe** Restoration Complete phase. During a PSPS event, PGE will communicate with Public Safety Partners, operators of utility-identified Critical Facilities (including Communications facilities), customers, and other stakeholders at the intervals identified in Table 8. PGE will provide priority notifications to Public Safety Partners, Adjacent Public Safety Partners, and operators of utility-identified critical facilities beginning 72-48 hour prior to de-energization, if possible.

In addition, prior to and during PSPS events, PGE makes current PSPS status information, information including location, de-energization estimates, and estimated restoration times (ERTs) for each impacted PSPS area, available on www.portlandgeneral.com's wildfire and PSPS outage webpage. All PSPS information on portlandgeneral.com will be easily readable and accessible on mobile devices.

Table 8: PSPS Notification Cadence

Notification Cadence	Audience		
	Public Safety Partners, Adjacent Public Safety Partners, Stakeholders	Utility-identified critical facilities[1]	Customers
PSPS Warning 72-48 hours prior to de-energization	✓	✓	
PSPS Likely 48-24 hours prior to de-energization	✓	✓	✓
PSPS Imminent 4-1 hours prior to de-energization	✓	✓	✓
PSPS Happening At de-energization	✓	✓	✓
Restoration Begins	✓	✓	✓
Restoration Complete	✓	✓	✓
At a minimum, status updates at 24-hour intervals until service has been restored[2]	✓	✓	✓

Notes

[1] Including Communications facilities

[2] These notifications may be required any time after initial notifications during **Level 3: Elevated** through restoration, as dictated by the event

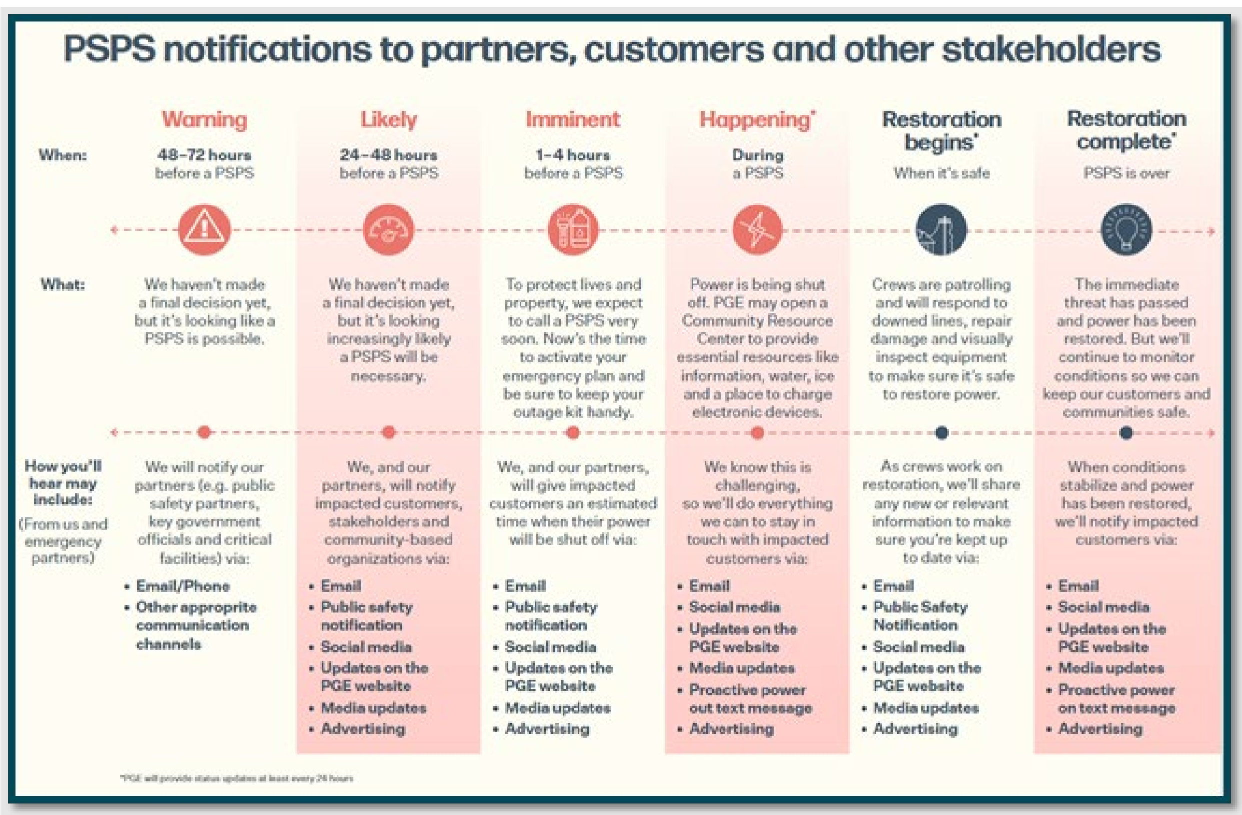
PGE will use multiple media channels, including owned, earned and sponsored channels, to inform impacted customers, communities and stakeholders throughout the PGE service area in accordance with OAR 860-300-0050, with special attention to those within the affected PSPS Area(s). PGE will deliver notifications in multiple formats across multiple channels that may include, but are not limited to, phone calls, text messages, prepared public safety notifications distributed through Public Safety Partners, social media posts, media advisories, emails, and messages to agencies that serve diverse community populations. For PSPS outreach to customers and stakeholders, PGE aims to address the geographic and cultural demographics of the PSPS Area, including languages spoken, access to broadband, and accessibility for those who are visually or hearing impaired, through the following strategies:

- All of PGE's PSPS-related written communications are provided in English and Spanish.
- PGE Customer Service offers a Language Hotline that can answer customer questions in 200 languages.

- PGE works closely with Public Safety Partners and the broadcast and print media to provide regular PSPS-related SMS (text) messages and news reports to help customers who may not have in-home broadband access stay informed throughout the PSPS event.
- All of the PSPS-related content on the portlandgeneral.com website is designed to be ADA-A-compliant[6]; for vision- or hearing-impaired customers, PGE provides both audible and written messaging options, as well as closed-captioning on all videos posted to the website.
- Throughout the event, PGE disseminates its PSPS-related messaging via as many platforms and formats as possible to facilitate the widest possible reach—text messaging, online content, traditional media, paid advertising, written materials and customer service in multiple languages, closed captioning—and works with community-based organizations and Public Safety Partners to reach as many impacted customers as possible.

PGE recognizes the criticality of effective communication to stakeholders before, during, and after a PSPS event; to the extent practicable, the following figure provides a visual summary of PGE's PSPS notifications process.

Figure 14: PSPS Notifications Strategy



Throughout the PSPS event, PGE will provide the elements of notification information required by OAR 860-300-0050 to Public Safety Partners, Adjacent Public Safety Partners, operators of Utility-

[6] Reference to Web Content Accessibility Guidelines: https://www.w3.org/WAI/WCAG21/quickref/

identified Critical Facilities (including communications facilities), and customers as summarized in Table 9.

Table 9: Notification Information

Notification Information	Audience		
	Public Safety Partners, Adjacent Public Safety Partners, Stakeholders	Utility-Identified Critical Facilities	Customers
Date and time PSPS will be executed	√	√	√
Estimated duration of PSPS	√	√	√
Notice of when re-energization efforts will begin and when re-energization is expected to be complete	√	√	
At a minimum, status updates at 24-hour intervals until service has been restored	√	√	√
Number of customers impacted by PSPS	√		
The PSPS zone, which would include Geographic Information System shapefile(s) depicting current boundaries of the area subject to de-energization	√	√	
When feasible, the Public Utility will support Local Emergency Management efforts to send out emergency alerts	√		
A statement of impending PSPS execution, including an explanation of what a PSPS is and the risks that the PSPS would be mitigating			√
A 24-hour means of contact customers may use to ask questions or seek information			√
How to access details about the PSPS via the Public Utility's website, including education and outreach materials disseminated in advance of the annual Wildfire Season			√

Note

[1] Specifically provided to Operators of Communications Facilities located within the area(s) of the anticipated PSPS.

10. Ignition Prevention Inspections

PGE conducts annual Ignition Prevention Inspections within its 10 HFRZs, as well as in areas subject to heightened wildfire risk within PGE's right-of-way for generation and transmission assets located outside of PGE's service territory. PGE inspects each supporting structure (pole or tower) within the HFRZs or area subject to heightened risk each year – approximately 26,000 structures in all, scattered across more than 1,000 line-miles located within PGE's service territory and over 100 line-miles located outside of PGE's service territory. The following table quantifies the number of assets inspected:

Table 10: PGE Structures Surveyed 2022

Location	Structure Count	Line Miles
PGE HFRZs 1-10	25,250	1,100
PGE Generation and Transmission Assets Outside Service Territory	750	100

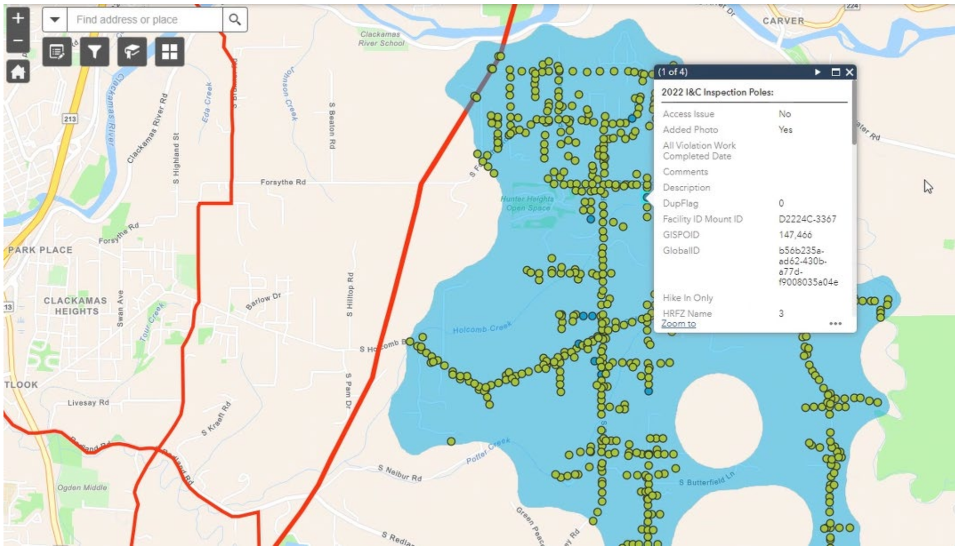
10.1 Ignition Prevention Inspection Procedures

PGE's Ignition Prevention Inspections are performed in-person. Under PGE's Inspect-Correct methodology, crews perform inspection tasks and complete most corrections during the initial visit to the structure, significantly reducing PGE's average correction times, and reducing customer impacts by eliminating the need for multiple site visits.

Within PGE's service territory, crews visually inspect distribution system support structures, lines, and equipment from the ground using binoculars or a spotting scope mounted on a tripod; physically measure vegetation and structural clearances; and sound each wooden supporting structure to detect internal damage or decay. The crew may drill the pole or capture more detailed measurements to assess the extent of damage or decay in more detail. Crews use a standard form (see Appendix 2) to consistently and repeatably record conditions during the field inspections and capture digital photos of each supporting structure using mobile GIS software.

Figure 15 illustrates the data displayed and tracked through PGE's mobile GIS structure tracking application:

Figure 15: PGE ARCGIS Online Structure Tracking Data



PGE also uses the Inspect-Correct methodology to annually inspect over 170 distribution poles located near its generation facilities in areas of heightened risk outside of the PGE service territory.

Ignition Prevention Inspections conducted outside of PGE's service territory primarily address conditions in the right-of-way (ROW) for PGE 230 kV or 500 kV transmission facilities. These inspections are performed by PGE Transmission Patrolmen with detailed knowledge of how these transmission facilities are constructed, operated, and maintained, including specialized knowledge of supporting structure bonding and grounding configurations. The PGE Transmission Patrolmen visually inspect the supporting structures, lines, and equipment from the ground using binoculars, and use drones to assess conditions in the overhead space. PGE Transmission Patrolmen also use a standard form to consistently and repeatably capture conditions during the inspections.

10.2 Ignition Prevention Inspection Standards

PGE's Ignition Prevention Inspection standards build upon several years of PGE experience in administering its Facility Inspection and Treatment to the National Electrical Safety Code (FITNES) Program, which satisfies OAR 860-024-0011 and OAR 860-024-0012. The FITNES Program inspects approximately 28,000 poles annually, or approximately 10 percent of PGE's system, for non-compliance with safety rules governing PGE's and pole occupant facilities.

PGE continues to refine its Ignition Prevention Inspection work practices through active participation in industry discussions and forums. In 2023, based on feedback received from OPUC Safety Staff, PGE will continue to include inspection standards relating to conductor attachments to trees.

PGE's Ignition Prevention Inspection standards direct inspection teams to identify conditions which, left unaddressed, could lead to vegetation or wildlife contact with energized conductors or equipment and, potentially, an ignition event. PGE's Ignition Prevention Inspection standards address the following inspection categories:

- Damaged/broken/missing/loose hardware and equipment

- Damaged conductor
- Conductor clearances
- Bonding
- Damaged/decayed poles
- Broken lashing wire
- Tree attachments
- Other potential sources of ignition

A full list of PGE's Ignition Prevention Inspection standards is found in Appendix 2. PGE will update these standards as required to reflect updated information or OPUC guidance.

PGE 's HFRZ Ignition Prevention Inspections may be combined with other safety or detailed inspections as required by OAR 860-024-0001(6). To avoid multiple inspections of the same pole each year, PGE's ignition prevention inspections may also incorporate the safety patrol standards described in OARs 860-024-0011(2)(c) and 860-024-0018(4). Depending on the facility to be inspected, PGE may also choose to accomplish both the FITNES inspection (OAR 860-024-0011(1)(b)) and ignition prevention inspection during the same site visit.

10.3 Ignition Prevention Inspection Program Oversight

PGE's Ignition Prevention Inspection Program management team oversees project management, administration, fieldwork, technical support, and management oversight and reporting.

Each year, prior to the start of the inspection season, the crews responsible for PGE's ignition prevention inspections undergo in-depth training covering the following major topic areas:

- Scope and locations of the inspections
- Inspect/Correct standards, including printed specifications showing which conditions to inspect for and correct, with diagrams and example photos
- Inspect/Correct procedures, including how to conduct the visual inspection, identify pole occupants, obtain measurements, and capture digital photos
- Inspection software, with hands-on training in use of the GIS software
- Required crew configuration, tools and equipment, and materials
- Communications protocols between PGE and the vendor conducting the inspections
- Protocols for communicating with customers prior to accessing private property
- Quality Assurance requirements
- Other requirements associated with vendor performance
- Wildfire awareness and suppression safety training

During the initial one to two weeks of the HFRZ ignition prevention inspection period, each inspection crew is accompanied by a PGE observer who verifies work performed, provides feedback, and answers questions. During the remainder of the inspection period, PGE performs weekly QA/QC of each crew's work. New crews added during the inspection season are required to complete the same training and initial PGE observer requirements.

Ignition Prevention Inspections conducted outside of PGE's service territory but within the ROW for its 230 kV and 500 kV transmission facilities are accomplished by PGE Transmission Patrolmen and directed through monthly coordination meetings. PGE Lead Working Foremen are responsible for QA/QC of each Transmission Patrolman's work.

The Ignition Prevention Inspections Program is monitored by the assigned PGE project manager, using a GIS dashboard that monitors each supporting structure located in an HFRZ or area of heightened risk. PGE monitors inspection results daily during the inspection season.

10.4 Ignition Prevention Inspection Timing

Annual HFRZ Notifications

Per OAR 860-024-0011(2)(b), PGE will notify all Owners and Operators of Facilities of any geographic changes to the HFRZ in which their facilities are located no later than 60 days before the start of the 2023 Ignition Prevention Inspections. The number and geographical boundaries of PGE HFRZs are reassessed annually and are subject to change as system hardening projects are completed and new information and analysis becomes available.

Timing of Annual Ignition Prevention Inspections

PGE's goal is to begin its annual ignition prevention inspections as early as possible during the calendar year and to complete the inspections no later than July 31, with the majority of inspections completed prior to PGE's declaration of the start of 2023 Fire Season. Accumulated snowfall at higher elevations within the HFRZs and areas of heightened wildfire risk may delay the inspection process in some areas by hindering physical access to supporting structures and obscuring defects on conductors or equipment.

HFRZ Inspect-Correct Timeframes

PGE categorizes HFRZ corrections and specifies their mitigation timeframes as follows:

- A condition that poses an imminent danger to life or property must be repaired, disconnected, or isolated by the operator immediately upon discovery
- A condition that correlates to a heightened risk of utility-caused ignition shall be corrected no later than 180 days after discovery unless an occupant receives notification under OAR 860-028-0120(6) that the violation must be corrected in less than 180 days to alleviate a significant safety risk to any operator's employees or a potential risk to the general public
- All other conditions requiring correction shall be corrected consistent with OAR 860-024-0012.

PGE recognizes that OAR 860-024-0018 sets forth several new duties for operators of electric facilities, including requirements to address conditions not associated with PGE facilities and conditions involving supporting structures to which PGE is attached but does not own. With respect to conditions associated with other pole occupants, PGE will comply with OAR 860-024-0018(8) – 860-024-0018(11) and utilize remediation tools afforded to Operators of electric facilities by the OPUC's High Fire Risk Zone Safety Standards.

10.5 Ignition Probability Values and Historic Ignition Tracking

In 2021, in response to new OPUC requirements, PGE created an ignition management tracking database and process. This allows PGE to evaluate the system hardening investments described in the Targeted Interventions to Reduce Wildfire Risk Section, below, in light of the risk drivers that deliver an optimized risk/spend efficiency calculation. For example, if analysis shows that georisk represents a feeder's only risk, but 99 percent of all the ignitions recorded at that site are caused by animal contact, then installing animal protection devices would likely be the appropriate risk mitigation outcome for that location.

As PGE collects risk assessment data and supplements it with lessons learned and industry best practices, it refines its ignition probability values database to create more accurate risk projections. These risk projections, based on quantifiable drivers, allow PGE to map risk velocity (risk forecasted through time) and link it to the various strategies described in Section 6.5, Wildfire Risk-Based Decision-Making, to drive highest-value risk mitigations.

10.6 Ignition Reporting Requirements

PGE tracks ignitions potentially caused by PGE equipment, as well as fires that impact PGE facilities. Relevant tracking and reporting include documentation of the initial observation and recording of ignition events in the field, as well as the specific geographic and ROW location of any impacted PGE equipment.

PGE conducts a review of any ignition events reported in the field, and documents relevant data for submission to the OPUC. In addition, PGE tracks and reports the progress of ignition event reports submitted to the OPUC and archives its OPUC ignition event reports for future compliance purposes. Historic ignition event data[7] is used to inform strategic asset management decisions, including system hardening measures, with a more granular understanding of risk. PGE plans to continue to build out this ignition tracking/reporting database as a key component of understanding ignition events by drivers.

[7] PGE has been tracking historic ignition event data since May 2021

11. Vegetation Management

PGE's vegetation management strategy has two major components: PGE's Routine Vegetation Management (RVM) program and the Advanced Wildfire Risk Reduction (AWRR) program. PGE will continue to implement a phased approach to implementation of its AWRR work within the HFRZs. One of the primary goals of PGE's Vegetation Management program is to annually inspect and mitigate identified trees within its HFRZs. PGE establishes internal targets for completion of various work scopes in line with the activities listed below.

11.1 Routine Vegetation Management (RVM) Inspection & Maintenance

Under its RVM program, PGE manages approximately 2.2 million trees within its ROW of 12,000 miles of overhead conductor. In recent years, PGE has expanded its vegetation management program to trim with increased clearances and remove more vegetation that is dead, dying, diseased, or displaying growth habits or defects that could impact overhead power lines. PGE performs cyclic patrols and trims vegetation to comply with OAR 860-024-0016 minimum conductor vegetation clearance standards. During routine maintenance inspections, PGE also patrols for and mitigates readily climbable vegetation.[8] PGE documents relevant tree trimming plans and makes them available to the OPUC upon request.

Under its RVM program, PGE inspects about one-third of its overhead distribution assets annually. Routine inspection timing may change as PGE evaluates the effectiveness of its vegetation management cycles to optimize effectiveness and efficiency. Across PGE's overhead system, routine vegetation management activities are ongoing year-round.

PGE inspectors evaluate all vegetation adjacent to PGE facilities, including PGE-owned communications facilities, for proximity, species, growth habits, strength, and overall tree health. When assessing trees along powerlines, PGE considers the following in its vegetation management prescriptions:

- Line voltage
- Location
- Line configuration
- Potential sag under various environmental conditions, and

[8] OAR 860-024-0016(1) "Readily climbable" means vegetation having both of the following characteristics: (a) Low limbs, accessible from the ground and sufficiently close together so that the vegetation can be climbed by a child or average person without using a ladder or other special equipment and (b) A main stem or major branch that would support a child or average person either within arms' reach of an uninsulated energized electric line or within such proximity to the electric line that the climber could be injured by direct or indirect contact with the line.

- Clearance requirements to avoid off-cycle trimming.

PGE inspectors create project-specific work layout for vegetation contractors to complete while moving through the system performing RVM activities. Line clearance trim specifications are designed to maintain vegetation clearances during routine wind and adverse weather conditions. At a minimum, PGE adheres to the voltage-based clearance requirements specified in OAR 860-024-0016. PGE vegetation contractors trim identified trees to PGE specifications during the three-year standardized maintenance cycle to comply with OAR Division 24 Safety Standards (Division 24), ORS 758.282 and 758.284, and ANSI A300 and OSHA Z133 guidelines.

In addition, RVM work is field-validated by PGE forestry personnel who work closely with the crews to confirm completion. PGE subjects its vegetation management activities to a detailed QA/QC process to verify that vegetation management tasks have been completed to specification. To increase RVM program effectiveness, PGE also coordinates vegetation management activities closely with external stakeholders, including USFS, ODF, Oregon Department of Transportation (ODOT), municipalities, and private landowners.

11.2 Advanced Wildfire Risk Reduction (AWRR) Vegetation Management Program for HFRZs

AWRR operations fall outside of PGE's routine maintenance and trimming operations as the AWRR scope, operational practices, inspection schedule, and cadence are all on escalated cycles. AWRR program activities are guided by the results from PGE's Wildfire Risk Assessment modeling program.

For 2023, PGE has continued to refine its vegetation management activities, including the AWRR program, to address current climatic conditions and focus on OPUC requirements. ORS 758.280-758.286 provides PGE's operational framework for AWRR-related activities, as most of this work occurs outside of designated PGE ROW, utility easements, and annual maintenance schedules.

Under the AWRR program, PGE performs annual vegetation inspections on overhead line mileage that falls within HFRZs, mitigates vegetation based upon inspection results, performs QA/QC of vegetation management work completed by crews, documents its vegetation management activities, and coordinates them with county, municipal, and other external agencies, including ODOT, ODF, and USFS.

PGE closely manages AWRR program work to verify that it is completed to PGE specifications, from the establishment of the AWRR work schedule at the beginning of the year through QA/QC of the completed work. AWRR vegetation prescriptions follow program specifications, which include more stringent inspection and maintenance cycles and tree removal guidelines than those required under Division 24.

Tree removal practices associated with AWRR are applicable to any tree within striking distance of PGE electrical infrastructure, regardless of the tree's condition. PGE classifies trees that are an imminent hazard to PGE facilities as "P1" trees. PGE classifies trees that pose a probable hazard to the line or facility as "P2." A P2 designation can refer to any tree condition that could create a hazard to a PGE line or facility—trees that are dead, dying, diseased, or damaged, or that have fungal or insect infestation or stress, sunscald, overall poor health, mechanical damage, multiple tops, poor site conditions, conks on trunk, excavation or aggradation in the root zone, as well as trees that are located too close to PGE facilities.

In 2023, PGE will conduct as much of the AWRR Program's vegetation and P1 inspections and subsequent trimming and P1 mitigation within designated HFRZs as possible during the first six months of the year, although this work is ongoing throughout the year.

Figure 16: SlashBuster Clearing Right-of-Way

Figure 17: 105′ Aerial Lift Removing Dead Tree on Border of AWRR Zone

11.3 Inspection & Maintenance Frequencies for AWRR

Table 11: PGE HFRZ Inspection & Maintenance Strategies

AWRR Mitigation	Inspection or Maintenance	Cadence	Description
Clearance and P1 Inspection	Inspection	Annual	During this inspection, PGE AWRR inspectors identify vegetation that is within 5′ of high-voltage conductors, and newly established vegetation that is not suitable for a given location. Inspectors verify ongoing vegetation clearance compliance and identify any vegetation that has encroached on PGE assets since the previous inspection. AWRR inspections occur annually, outside of the RVM program's 3-year vegetation maintenance cycle. Inspectors also identify any P1 trees.
Clearance and P1 Mitigation	Maintenance	Annual	Trees/vegetation identified by the AWRR inspectors as too close, and/or wrong tree for the location are trimmed back to proper specification by tree crews. PGE mitigates all P1 hazard trees as quickly as possible, frequently within 24 hours of identification.
Enhanced Vegetation Inspection	Inspection	Annual, ongoing	PGE performs a comprehensive inspection along designated HFRZ lines for all potential P2 trees. PGE is currently tracking stems of large diameter trees within minimum approach distance that are mature and not susceptible to movement. PGE will be reviewing these trees for safety every year. In addition, AWRR inspectors identify and target specific sections of line that require more intensive clearance work, including increased side-clearance, overhang removal, selective removal of tree parts, expansion of ROW widths, ROW mowing, and whole tree removal.
Enhanced Vegetation Trimming and Mitigation	Maintenance	Annual, on-going	PGE removes or otherwise mitigates P2 trees on an ongoing basis throughout the year. Once planned, PGE enhanced vegetation trimming and removal projects are executed as seasonal conditions allow. PGE will mitigate any large-diameter trees that show decline from conditions recorded in the AWRR database appropriately. Due to the scale and logistics of P2 mitigation, some projects planned for a given year may carry over for completion in the subsequent year.

12. Expected Wildfire Program Costs

PGE develops an annual budget of implementation and administrative costs, as well as forecasted capital budgets, for the Program. The activities and expenditures generally included in these budgets include:

Wildfire-Related Operations & Maintenance (O&M):

For 2023, Program operation and maintenance (O&M) includes, but is not limited to:

- Wildfire Mitigation Program implementation
  - Wildfire training (described in Section 8)
  - Wildfire-related staff
  - Wildfire Analytics and Planning and tool development (described in Sections 5 and 6)
- Vegetation management, wildfire-related (described in Section 11)
- Support Areas
  - Community Resource Centers and costs (described in Sections 9 and 12)
  - Portable battery pilot (described in Section 15)
  - Wildfire-related outreach and education costs (described in Section 13)
  - Engineering (described in Sections 9 and 15)

Table 12: 2023 PGE Wildfire Mitigation O&M and Capital Costs

HFRZ 1-10 O&M	
Activity	**Cost (2023)**
Wildfire Mitigation Program	$4.7M
Inspections	$3.1M
Vegetation Management	$14.8M
Support Areas (Includes CRCs, Communications, Engineering, Portable Battery Pilot)	$1M
TOTAL	**$23.6M[9]**

[9] This budget is based on the 2022 General Rate Case decision dated 04/25/2022.

HFRZ 1-10 Capital	
Cost Area	**Cost (2023)**
Wildfire Mitigation & Resiliency	\$9 M-\$20.9 M[10]
Utility Asset Management (Project Management Office)	\$5.3 M
Utility Asset Management	\$0.8 M
TOTAL	**\$15.1 M - \$27.0 M**

For reference, as of filing this WMP, PGE's \$15 million 2022 capital investments for wildfire mitigation included:

- 23 additional weather stations
- 20 AI cameras in HFRZ
- 11 miles of copper replacement (construction started fall 2022)
- 44 Smart Reclosers/TripSavers
- PGE exceeded its 2022 Fuse Replacement Program goal of 480 by installing 979 non-expulsion (fire-safe) fuses.

PGE will continue to refine its Wildfire Risk Mitigation Assessment program in 2023 and beyond and will continue to forecast its WM&R capital and O&M spending needs based on the results of that analysis. PGE's planned programs may be augmented if PGE is successful as it actively pursues State and Federal grant funding for a variety of wildfire risk reduction and resiliency improvement projects. These programs include FEMA BRIC grants and the DOE Bipartisan Infrastructure Bill (BIL) with grant funding opportunities through the Grid Resilience and Innovation Partnerships (GRIP) section. PGE is also exploring additional opportunities through the State of Oregon's formula grants under the BIL.

[10] Project designs are currently in various stages of completion

13. WMP Engagement, Public Outreach and Awareness, and Public Safety Partner Coordination

13.1 Engagement, Outreach and Coordination Overview

PGE's employs a three-pronged approach to collecting feedback, educating, and coordinating with customers and stakeholders regarding the WMP. It includes:

- WMP Engagement Strategy
- Community Outreach and Awareness Strategy
- Public Safety Partner Coordination Strategy

PGE's WMP Engagement Strategy is focused on building long-term relationship and equitable engagement with a diverse set of community members, using the guiding principle "Nothing about me without me." PGE actively seeks to understand the needs and wishes of the communities it serves.

The Community Outreach and Awareness Strategy focuses on educating customers and communities about PGE's wildfire mitigation efforts and preparing them for the possibility of wildfire or PSPS events. Outreach and awareness are year-round efforts using multiple mediums and communication channels to reach customers and community stakeholders. PGE values close working relationships with its Public Safety Partners and considers them integral to the success of a well-coordinated Wildfire Mitigation Program. PGE's Public Safety Partner Coordination Strategy outlines the format and cadence of coordination for these efforts.

13.2 2022 Public Safety Partner Coordination and Collaboration

PGE collaborated with its Public Safety Partners via multiple channels in 2022 to support development of the 2023 WMP. Those engagement channels included After Action Review (AAR) processes for both the PSPS Tabletop Exercise at PGE's Integrated Operations Center on May 13 and for the September 2022 PSPS event, as well as a PGE-facilitated Pano AI workshop with fire agencies in October.

PSPS Tabletop Exercise AAR

During the exercise, participants commented that Public Safety Partners would benefit from having input into the refinement of PGE's public notification templates, as there is specific information that external partners and stakeholders will request and need access to during a PSPS event.

Public Safety Partners expressed their appreciation that they were included in the exercise. Participants commented that it would be beneficial to conduct a functional exercise to allow all partners to work through a PSPS event collaboratively, in real time.

September 2022 PSPS Event

PGE also solicited feedback from its Public Safety Partners during the AAR process following the September 9–12, 2022 PSPS event. Some of the suggestions that PGE is working to incorporate in its 2023 Program include:

- Host a Public Safety Partner workshop to allow external stakeholders to advise and support clarification of cross-jurisdictional coordination responsibilities for alerts and warnings
- Evaluate alongside Public Safety Partners the use of Wireless Emergency Alerts for PSPS events and define policies and agreements to facilitate its successful deployment and reduce "overspray" confusion for notification recipients.
- Build a county partnership model to support Public Safety Partner-hosted locations with water and ice donations
- Hold a work session with Public Safety Partners, including ESF-12, to share information about CRCs, locations, information sharing, and other incident support services for community members
- Develop centralized dashboards, status hubs, and granular data feeds readily accessible to all stakeholders, with emphasis on dashboards targeted to all PGE employees, Public Safety Partners, and customers
- Evaluate a method to further granulate GIS data to identify the current stage of the PSPS event for each PSPS Area.

A more detailed description of PGE's engagement with Public Safety Partners and lessons learned during the September 2022 PSPS event is available in PGE's ***PSPS Annual Report*** to the OPUC.

Pano AI Partnership

On October 19, 2022, PGE held a workshop with representatives from Pano AI and six Oregon fire agencies to coordinate development opportunities for situational awareness. Participants discussed how the Pano AI wildfire camera technology is improving detection/alerting processes and decision-making, learned more about existing Pano AI capabilities, and discussed potential improvements to the platform's features and tools. For example, workshop participants explored the feasibility of capturing weather data at the camera locations to provide real-time meteorological condition information to responders. The group also discussed the potential for this technology to improve emergency evacuation processes by sharing access and data with law enforcement agencies county to county and even state to state.

13.3 2023 WMP Engagement Strategy

PGE's 2023 WMP Engagement Strategy is influenced by the community feedback captured during the 2022 program year (see Appendix 3 for comments received during PGE's 2022 WMP engagement sessions) and will focus on continuing to proactively engage and collaborate with PSPs, local communities, and customers. The annual Wildfire Mitigation planning process provides PGE with the opportunity to solicit feedback on its WMP and strengthen long-term engagement relationships with Public Safety Partners and local community members.

PGE's engagement methods are shaped by OPUC compliance rules and recommendations, as well as the iterative feedback received from Public Safety Partners, community-based organizations (CBOs), local community stakeholders and customers throughout the year. The metrics and criteria PGE uses to evaluate engagement effectiveness include quantitative metrics such as number of participants/attendees per event and workshop ratings/scores, as well as qualitative feedback received during and after each engagement event. Although the specific schedule for these events has not been established at this time, PGE's 2023 WMP engagement activities may include:

- Anticipate contracting with a qualified communications, outreach, and public involvement consultancy with strong ties to local communities to help PGE host a series of WMP engagement sessions across the PGE service territory.
- Hosting at least one WMP engagement session within each county (or group of adjacent counties within reasonable geographic proximity), with access and functional needs considerations, in its service territory. Participants will be able to attend these public workshops in-person or virtually.
- Holding a pre-planning session with Public Safety Partners to identify any language or functional needs to be accommodated during public engagement sessions.
- Capturing WMP feedback from both in-person and virtual WMP engagement session participants to better understand the needs and concerns of those most impacted by PGE's wildfire mitigation efforts, while meeting OPUC rule requirements.
- Providing additional feedback opportunities through follow-up surveys, to further inform the 2024 WMP.

One of the main goals of PGE's WMP Engagement Strategy is to complete all engagement session planning by the end of the first quarter of 2023, with the aim of delivering these sessions as early as the second quarter of 2023. One of the key takeaways from PGE's 2022 engagement sessions was the importance of the timing of these events. PGE will focus on delivering its 2023 WMP Engagement Strategy events during the peak of Fire Season and/or when wildfire concern and activity is at its highest, rather than too early or late in the year.

PGE's 2023 WPM Engagement Strategy will consider including breakout stations/tables for PGE's Public Safety Partners, engaging American Sign Language and Spanish-speaking interpreters for the virtual or onsite events, and offering a virtual or onsite Spanish-only community engagement event.

13.4 Wildfire Community Outreach and Awareness Strategy

The goal of PGE's 2023 Wildfire Community Outreach and Awareness Strategy is to take a comprehensive and cohesive approach in communicating directly with community stakeholders and partners, customers, and the general public about PGE's wildfire mitigation efforts. The purpose of this strategy is to prepare communities for Wildfire Season by providing information about specific preparedness actions they can take, as well as steps PGE may take, including PSPS events. Outreach methods will reflect an umbrella approach that covers multiple partners, stakeholders, and channels to reach customers and communities throughout the PGE service territory. This approach will also incorporate stakeholder, Public Safety Partner, and customer feedback, as well as insights from available data about how customers are engaging with the information PGE provides. PGE is developing a strategy for expanded collaboration with Public Safety Partners and Local Communities during the 2024 WMP development process.

PGE's efforts to connect with the target audiences for its community outreach and awareness program will begin with outreach to regulators, state and emergency response agencies, PSPs and local municipalities to raise awareness about PGE's HFRZs, beginning with the annual submittal of PGE's WMP and continuing through Fire Season. In 2023, PGE will provide these entities with information about steps PGE is taking to reduce the risk of wildfire, and about opportunities to participate in one of the scheduled informational conference calls and tabletop exercises prior to PGE declaring Fire Season. PGE conducts ongoing outreach to state agencies and government officials to share vital information about PGE's wildfire mitigation efforts and potential PSPS events.

13.4.1 Wildfire Communication & Awareness Channels and Campaigns

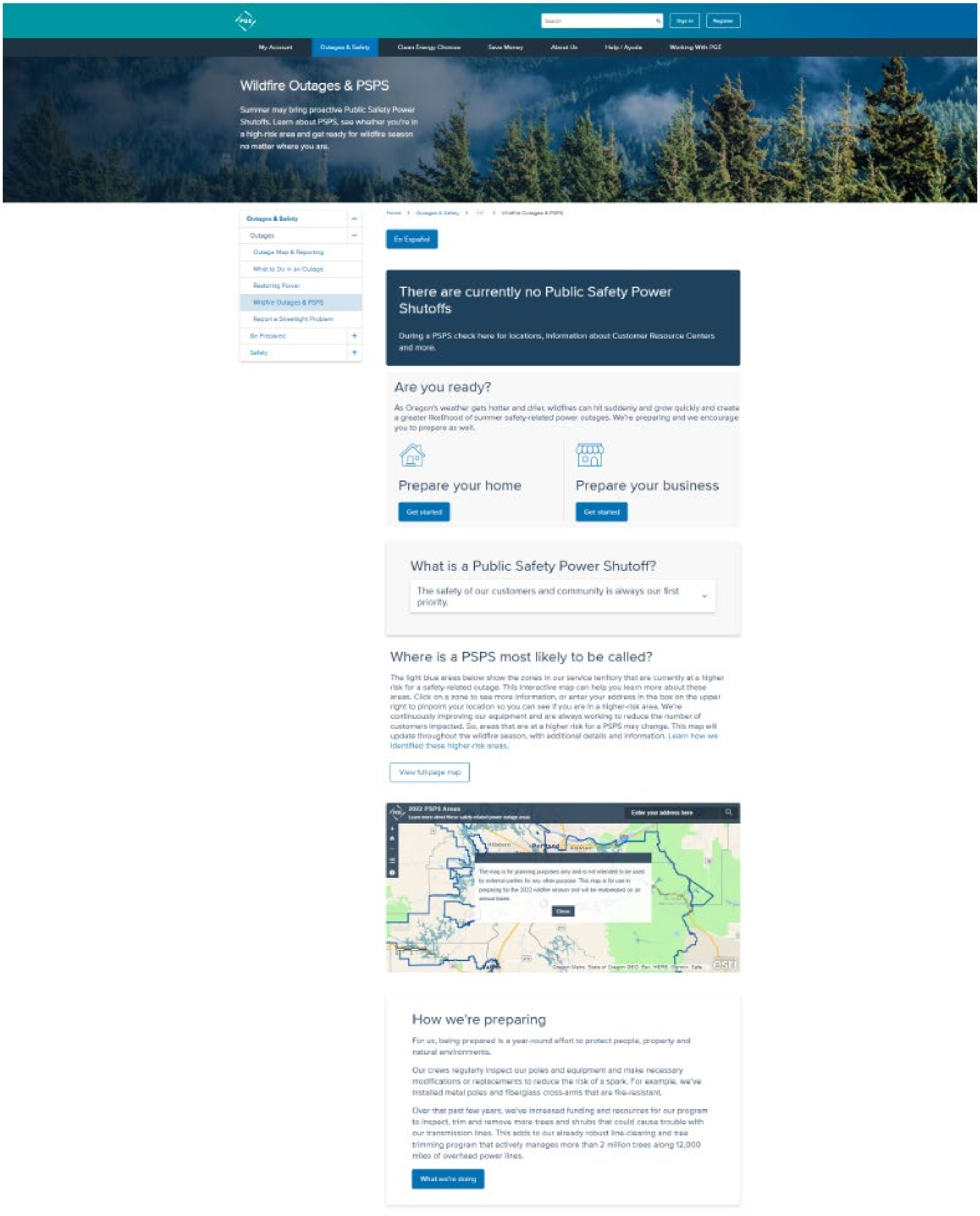
PGE employs a variety of tools and communication channels to broadly disseminate wildfire information and awareness and to ensure equitable information access for all members of the local community. For example, PGE has shared information with over 250 Community-Based Organizations (CBOs), food banks and school districts within PGE's service territory, enlisting their help in communicating with specific communities and customer groups to build awareness about the Wildfire Mitigation Program and potential PSPS events. PGE engages with CBOs by providing a toolkit (Appendix 7) of sample outage preparedness messages for use in social media, email, newsletter, and website messaging, in 15 languages (Arabic, Burmese, Chinese (simplified), Chinese (traditional), English, Farsi, Japanese, Korean, Rohingya, Romanian, Russian, Somali, Spanish, Swahili, and Vietnamese)—the most commonly spoken languages in PGE's service territory according to Oregon Census data. This learning has been validated through PGE's language line, which provides phone interpretation services in over 200 languages.

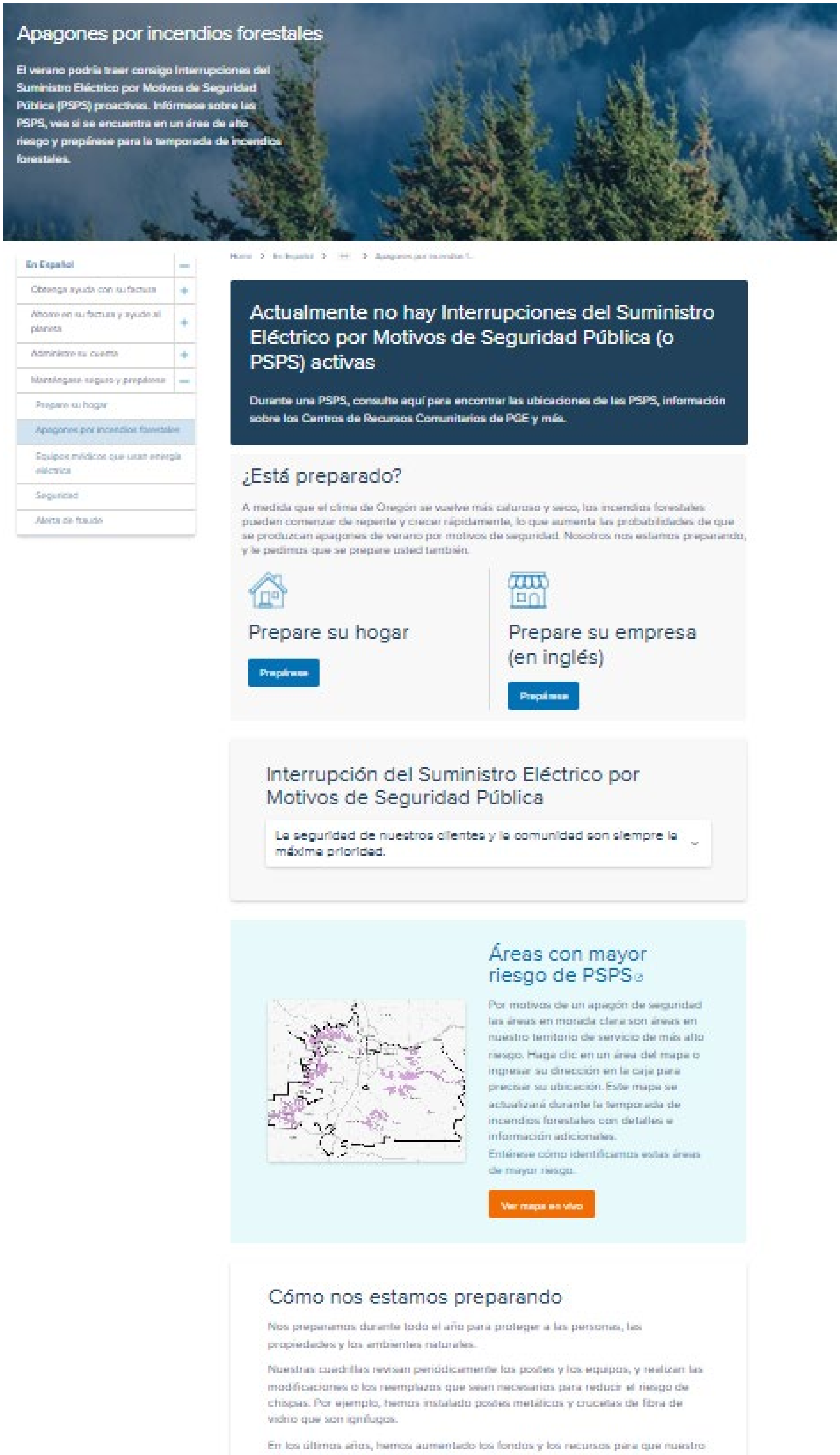
One of the main communication tools at PGE's disposal is the use of its public-facing website, (portlandgeneral.com) to communicate with all customers regarding wildfire awareness and PSPS preparedness. To provide stakeholders, partners, customers, and the public a central resource for wildfire-related information, PGE annually updates its wildfire outages web content in English and Spanish and provides a more specific set of information in 13 additional languages. The portlandgeneral.com wildfire pages provide information on the following topics:

- What is a Public Safety Power Shutoff?
- An interactive map of PGE's service territory and pre-identified PSPS areas, showing which zone (if any) is currently active. The map allows users to enter a service address to see whether it's located within the active area
- How to prepare a home or business for a PSPS event (which includes information about emergency plans, kits, and checklists)
- A high-level overview of PGE's wildfire preparation/mitigation strategy
- Information regarding how PGE's HFRZs were identified
- Factors considered in evaluating the likelihood of a PSPS event (e.g.: wind speed, temperature, humidity, the dryness of trees and brush, etc.)
- PSPS FAQs

Figures 18 and 19 provide examples of PSPS educational content found on the www.portlandgeneral.com website.

Figure 18: portlandgeneral.com's Wildfire Outages and PSPS Page (English and Spanish Versions)





Apagones por incendios forestales

El verano podría traer consigo Interrupciones del Suministro Eléctrico por Motivos de Seguridad Pública (PSPS) proactivas. Infórmese sobre las PSPS, vea si se encuentra en un área de alto riesgo y prepárese para la temporada de incendios forestales.

- En Español
  - Obtenga ayuda con su factura
  - Ahorre en su factura y ayude al planeta
  - Administre su cuenta
  - Manténgase seguro y prepárese
    - Prepare su hogar
    - Apagones por incendios forestales
    - Equipos médicos que usan energía eléctrica
    - Seguridad
    - Alerta de fraude

Actualmente no hay Interrupciones del Suministro Eléctrico por Motivos de Seguridad Pública (o PSPS) activas

Durante una PSPS, consulte aquí para encontrar las ubicaciones de las PSPS, información sobre los Centros de Recursos Comunitarios de PGE y más.

¿Está preparado?

A medida que el clima de Oregón se vuelve más caluroso y seco, los incendios forestales pueden comenzar de repente y crecer rápidamente, lo que aumenta las probabilidades de que se produzcan apagones de verano por motivos de seguridad. Nosotros nos estamos preparando, y le pedimos que se prepare usted también.

Prepare su hogar

Prepárese

Prepare su empresa (en inglés)

Prepárese

Interrupción del Suministro Eléctrico por Motivos de Seguridad Pública

La seguridad de nuestros clientes y la comunidad son siempre la máxima prioridad.

Áreas con mayor riesgo de PSPS

Por motivos de un apagón de seguridad las áreas en morada clara son áreas en nuestro territorio de servicio de más alto riesgo. Haga clic en un área del mapa o ingresar su dirección en la caja para precisar su ubicación. Este mapa se actualizará durante la temporada de incendios forestales con detalles e información adicionales.

Entérese cómo identificamos estas áreas de mayor riesgo.

Ver mapa en vivo

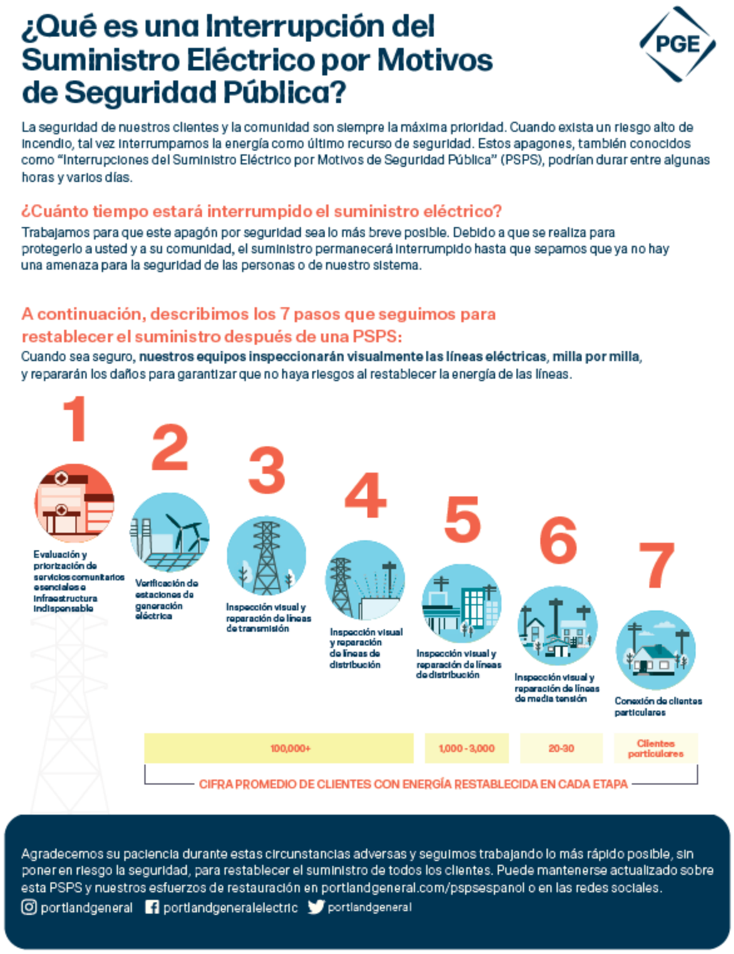
Cómo nos estamos preparando

Nos preparamos durante todo el año para proteger a las personas, las propiedades y los ambientes naturales.

Nuestras cuadrillas revisan periódicamente los postes y los equipos, y realizan las modificaciones o los reemplazos que sean necesarios para reducir el riesgo de chispas. Por ejemplo, hemos instalado postes metálicos y crucetas de fibra de vidrio que son ignífugos.

En los últimos años, hemos aumentado los fondos y los recursos para que nuestro programa revise, pode y quite más árboles y arbustos que puedan causar

Figure 19: “What Is a Public Safety Power Shutoff?” – Spanish Version



Additionally, PGE may attend wildfire preparedness events and town halls hosted by county and fire agencies, for the purpose of sharing information about the potential for wildfire-related power (PSPS) outages. In 2022, PGE attended five such events in Clackamas County and shared information and checklists for making an outage kit and preparing an emergency plan, as well as information about Public Safety Power Shutoffs, including when PGE may call them and why and what factors PGE will consider in making that determination, with reference to resources on portlandgeneral.com.

Figure 20: Flyer for 2022 PGE Community Wildfire Preparedness Events

For 2023, PSPS preparedness information provided on the www.portlandgeneral.com website will be available in 15 languages (see Section 13.4.1, above, for the full list). PGE will also provide PSPS preparedness checklists translated into multiple languages, available via the PGE website during Fire Season, as well as PSPS preparedness one-pagers to CBOs, food banks, and schools throughout the PGE service territory. In addition, throughout Wildfire Season, PGE references the Language Line on its website and customer communications. PGE Customer Resource Centers distribute fliers in multiple languages with the following message: "We speak your language. Our customer service advisors can assist you in 200+ languages. Call us at 503-228-6322."

As Wildfire Season approaches, PGE will activate a campaign to raise awareness of wildfire and the potential for PSPS events, including a Wildfire Safety Month press release in May, distributed to 280 media outlets in Oregon via FlashAlert. Additionally, PGE will send out wildfire awareness and PSPS preparedness emails and direct mail to targeted customer segments in English and Spanish.

Throughout Fire Season, PGE will issue additional press releases and/or generate media stories about wildfire preparedness, what a PSPS is, and when a PSPS may be called, using mass communications to reach broad audiences.

Additionally, PGE will share at least one communications toolkit[11] with messaging for use by Public Information Officers for cities, counties, and emergency response agencies in PGE's service area. In late spring and throughout Fire Season, PGE's Twitter and Facebook will regularly share graphics and information driving viewers to portlandgeneral.com for wildfire awareness and PSPS information. PGE has chosen these social media communications tools for breadth of reach.

In 2023, PGE plans to build on its 2022 communications, education, and preparedness campaigns, using these existing communications and educational channels as a baseline and working collaboratively with community leaders and PSPs to refine and update the direction and content as required to keep customers informed. Please refer to Appendix 4 for an inventory of PGE's 2022 efforts and channels utilized.

13.4.2 Outreach and Awareness Timing

In 2023, PGE will perform outreach and awareness activities prior to and during the 2023 Fire Season to reach customers, Operators of Critical Facilities, federal, state and local governments and elected officials, agencies, Tribes, and Public Safety Partners. Customer communications will begin in May, with cadence and medium tailored to specific target audiences including residential and business customers, key managed accounts, critical and pole customers, and customers inside and outside of PSPS areas. Communications will continue throughout Wildfire Season in the form of paid advertising (daily) and strategic direct customer outreach (every two to four weeks). Activities will follow the same seasonal timeline employed during in 2022. Refer to Appendix 5 for timeline details.

13.4.3 Outcome of 2022 Outreach and Awareness Efforts

Outcomes of 2022 outreach and awareness efforts are provided in Appendix 6, Outcomes of 2022 Outreach & Awareness Efforts.

13.5 Assessing Effectiveness of Wildfire Community Outreach and Awareness Efforts

In 2023, PGE, in partnership with its Public Safety Partners, will seek measurably equitable outcomes and metrics for its wildfire community outreach and awareness activities. Goals for PGE's community outreach and awareness activities include raising awareness for customers and other stakeholders regarding PGE's Wildfire Mitigation Program and building collaborative relationships with these groups. PGE will work to provide communications that are inclusive and meet people where they are by using languages they understand. These equitable outcomes and metrics include:

- **Outcome:** Deliver wildfire mitigation information and awareness in an approachable and accessible manner that benefits all community members

[11] Please see Appendix 7 to view sample 2022 toolkit materials.

- **Outcome:** Empower Public Safety Partners with access to timely and actionable information

PGE will measure the effectiveness of its outreach and awareness efforts through the use of surveys as well as the following metrics:

- **Customer Marketing**:
  - Site visits to our wildfire pages on portlandgeneral.com
  - Wildfire newsletter and email open and click-through rates
  - Click through rates on wildfire digital ads
- **Corporate Communications**:
  - Reach of wildfire press release
  - Breadth of coverage generated
  - Number of social media posts and engagement

Finally, PGE will use 2023 as a baseline year to start measuring customer wildfire awareness with annual surveys.

13.6 Public Safety Partner Coordination Strategy

PGE works closely with Public Safety Partners to facilitate information sharing, community outreach and wildfire preparedness and response. PGE defines Public Safety Partners as the OPUC's Emergency Support Function (ESF)-12, Local Emergency Management, Oregon Department of Emergency Management (OEM) and Oregon Department of Human Services (ODHS). PGE's Public Safety Partner Coordination Strategy is divided into three phases: prior to, during, and after Fire Season. By working in partnership with each Public Safety Partner, PGE can maximize the effectiveness of its outreach efforts and the size of the audience receiving these communications and improve operational coordination and information sharing. Meeting frequency and location will be determined in collaboration with our Public Safety Partners.

13.6.1 Prior To Fire Season

Before Fire Season, PGE will engage in joint planning processes and deliver presentations to Public Safety Partners at existing information sharing and preparedness coordination forums, as needed. PGE will include wildfire preparedness topics in one of the all-hazards quarterly summits with Public Safety Partners. PGE and ESF-12 coordinate on the location, time, and topics for quarterly summits. PGE will also coordinate with Public Safety Partners to implement the WMP Engagement Strategy.

PGE will also host at least one annual pre-Fire Season tabletop exercise with Public Safety Partners that will focus on PSPS notification procedures and processes. This tabletop will occur before the end of the second quarter of 2023 and will follow the Homeland Security Exercise and Evaluation Program (HSEEP) principles and guidelines. All Public Safety Partners will receive an invite to attend the tabletop exercise and participate in the associated AAR process. When possible, PGE will engage in exercises developed by other Public Safety Partners to improve interoperability during an actual event.

13.6.2 During Fire Season

Once PGE declares the start of the Fire Season, the company will inform its various Public Safety Partners regarding in-season operational modifications to the PGE system.

Additionally, during Fire Season, PGE enhances situational awareness monitoring and maintains a state of operational readiness. Should a new fire start or expanding fire threaten PGE infrastructure, a company representative will contact the agency and/or Incident Management Team (IMT)-identified point of contact to coordinate appropriate utility response. For all incidents, PGE acts as a cooperating partner when company infrastructure is at risk or has been impacted by a wildfire.

If an incident requires the activation of the PGE CIMT, PGE will notify impacted stakeholders and initiate in-person and virtual coordination activities. As required, PGE will deploy dedicated utility representatives to jurisdictional Emergency Operations Centers (EOCs), Emergency Coordination Centers (ECCs), or Incident Command Posts (ICPs).

After wildfire incidents, PSPS events or PGE-led tabletop or functional exercises, PGE will conduct an AAR process that is consistent with HSEEP and utility sector best practices, reviewing incident response and identifying continuous improvement action items. A detailed summary of input from our Public Safety Partners and lessons learned captured through exercises and events from 2022 can be found in Appendix 8.

13.6.3 After Fire Season

When the annual Fire Season ends, PGE will solicit feedback from Public Safety Partners about implementation of the Wildfire Mitigation Program and any opportunities for improvement. This feedback is solicited through phone calls and meetings.

14. Participation in National and International Forums

In 2023, as in previous years, PGE will be an active participant in a wide array of national and international industry forums addressing wildfire and outage-related issues.

Emergency managers from PGE, PacifiCorp, NW Natural, and BPA collaborate throughout the year as part of an Energy Emergency Management Team (EEMT). Annually, the EEMT exchanges contact information with the Northwest Coordination Center (NWCC) for emergency communications during Fire Season. Dispatch/Control Center numbers provided by the energy companies are for dispatch-to-dispatch communications. Emergency management contacts are provided for both NWCC and fire dispatch center personnel to assist with strategic decision-making and incident coordination.

In addition, PGE annually participates in a variety of industry forums that may discuss wildfire-related topics, including:

- **International Wildfire Risk Mitigation Consortium (IWRMC):** PGE participates with utilities from across the Western U.S., Canada, South America, and Australia to benchmark and share best practices for wildfire mitigation. The IWRMC is comprised of four working groups: Operations & Protocols, Risk Management, Vegetation Management, and Asset Management.

  PGE has leadership positions on the Operations & Protocols and Risk Management working groups. In 2022, PGE used this forum to benchmark its approach to wildfire risk mitigation assessment to industry best practices and accelerate its learning on capital investments while understanding the difference in the environments other industry participants experience. PGE also participated in the group to understand new technologies and their potential applicability to PGE operations, as well as vegetation management approaches from around the globe.

  Through the IWRMC, PGE is able to leverage lessons learned for specific wildfire mitigation strategies already implemented by other utilities: for example, the use of covered conductor to reduce wildfire risk. Utilities that implemented this strategy failed to account for detection, fire response, and failure modes that could result in wire-down events, increasing wildfire risk as covered conductor failed to de-energize, resulting in ignition events that were sometimes undetected for hours. This was a costly lesson learned for peer utilities, which were forced to remove and underground covered conductor in environments where that failure mode would be common. PGE customers benefit from the company's active participation in this forum as the shared data and review of mitigation strategy outcomes help PGE avoid pitfalls and select more cost-effective and successful risk mitigation measures.
- **Electric Power Research Institute (EPRI):** PGE engages with its research partners at EPRI through multiple programs to address wildfire mitigation research and is leveraging EPRI-led programs such as the Incubatenergy Network to gain knowledge of new technologies and start-ups in wildfire-related disciplines. PGE engages with EPRI at multiple leadership levels. The PGE President and CEO serves on the EPRI Board of Directors; a PGE Senior Vice President serves on the EPRI Research Advisory Council; multiple PGE Senior Managers and Directors

serve as Sector Council advisors, and dozens of PGE SMEs engage with EPRI at the program advisory and technical working group levels.

In partnership with EPRI, PGE sponsored the three-day Utility Wildfire Symposium on November 8–10, 2022, in Portland, attended by OPUC Commissioners and staff, representatives from research institutes and industry, and government officials. Attendees viewed demonstrations of wildfire-related technologies, heard presentations on current wildfire-related research, and discussed opportunities for new research projects and collaboration across participating entities.

EPRI was recently commissioned to conduct a study for the California Investor-Owned Utilities to determine which portable battery products are best-suited to back up medical devices during power outages (such as PSPS events). PGE has engaged with its research partners at EPRI to design a Portable Battery Pilot Project, in which PGE will study the feasibility of offering no-cost portable battery devices to PSPS-impacted residential customers also enrolled in PGE's medical certificate program (for additional details, please see Section 15.6, below).

- **Oregon Joint Use Association (OJUA):** PGE is active in the leadership of the OJUA, a non-profit industry workgroup whose mission involves building trust, cooperation, and organizational cohesion between utility pole owners, users, and government entities to promote the safe, efficient use of the ROW. The OJUA has featured educational presentations on the topic of wildfire mitigation at its past two annual meetings. Additionally, by administrative rule, the OJUA is an advisor to the OPUC on the adoption, amendment, or repeal of administrative rules governing utility pole owners and occupants.
- **Other National and Regional Forums:** PGE is actively engaged with industry research partners at the Western Energy Institute, Edison Energy Institute (EEI), and the U.S. Department of Energy. This is evidenced by PGE participation in the leadership of these organizations, as well as its active engagement in the industry technical sessions and conferences.
- **Regional Disaster Preparedness Organization (RDPO):** PGE actively participates in the RDPO, which encompasses the five Portland metro region counties (Multnomah, Washington, Clackamas, Columbia, and Clark), as a utility/energy sector participant and steering committee member. In this role, PGE provides the RDPO with insights and a utility perspective on issues. In addition, participation in this group has enhanced PGE's regional partnerships and provided insights into regional disaster resilience and preparedness initiatives.
- **Oregon Wildfire Detection Camera Interoperability Committee:** PGE participates in this committee, whose primary goals and objectives include developing and maintaining statewide wildfire camera detection system(s) and fostering coordination and collaboration among its members. The committee membership includes the Governor's Office, public safety agencies, fire agencies, emergency managers, USFS, Bureau of Land Management, Statewide Interoperability Coordinator, ODF (co-chair of the committee), the Oregon Hazards Lab at the University of Oregon (co-chair of the committee), Tribal representatives, and Oregon's investor-owned utilities.

PGE is also working with federal partners to support the Wildfire Working Group's interdisciplinary and interagency efforts, representing the utility sector in the President's 2022 wildfire meetings with cabinet secretaries to emphasize the need for continued leadership at the federal level on wildfires and shared responsibility on the matter, among other issues.

In 2022, PGE participated in site visits with the San Diego Gas & Electric and Southern California Edison wildfire mitigation teams. The purpose of this benchmarking trip was to accelerate PGE's learning toward mitigating wildfire risks from PGE assets, as well as how to communicate with and support our customers. The teams discussed risk analysis, incident management approaches, capital investment strategies, fire suppression tools, community resource models, and communication techniques. Some key takeaways from the visits include:

- Opportunities to leverage greater automated notification capabilities around PSPS communications
- Opportunity to develop stronger relationships with local media to broaden and deepen awareness around wildfire preparedness and PSPS communications
- Significant investments being made in reconductoring in areas where undergrounding is not feasible or cost-effective
- Southern California Edison has a robust electronic Customer Care Plan Dashboard on all impacted customers during a PSPS event, allowing them to drill down to the individual customer/meter
- Both utilities were providing grants to assist with wildfire burn opportunities
- Considerable investments were being made to acquire aviation assets (helicopters and drones) available to provide air support to combat wildfires
- The importance of robust and dedicated meteorology and wildfire communications teams.

One finding from PGE's benchmarking peer reviews is that CPUC Decision 21-06-034[12], which requires California IOUs to consider the needs of Medical Baseline and Access and Functional Needs Communities impacted by PSPS events, could have implementation and customer impacts for Northwest utilities. PGE Interviewed representatives from California IOUs to understand the findings and best practices they observed during the rapid deployment of this regulatory mandate, as well as challenges, uptake rates, and implementation best practices. These interviews led PGE to work with EPRI to create the Portable Battery Pilot Project described in Section 15.6.

[12] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/documents/decision-phase-3-gl.pdf

15. Research & Development

PGE is undertaking a variety of wildfire-related research projects with public and private research institute and industry partners.

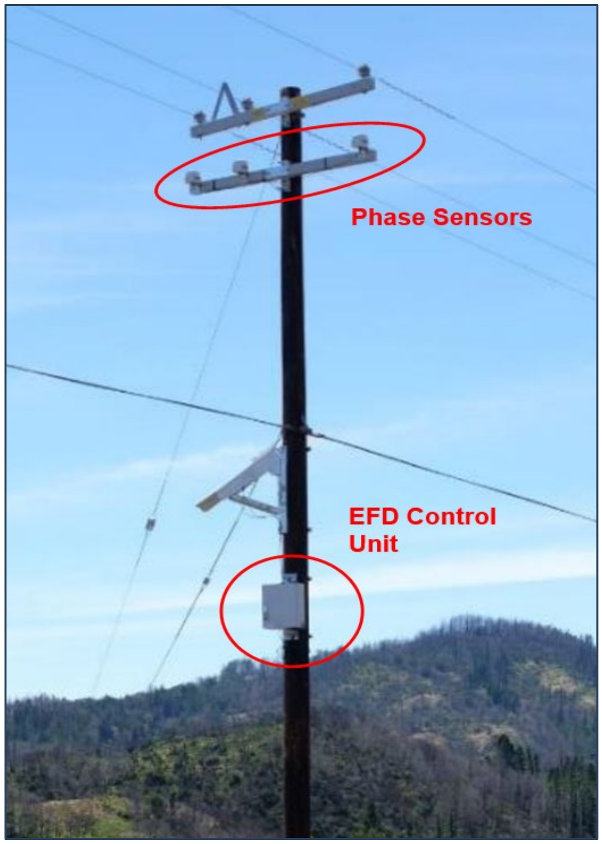
15.1 Early Fault Detection Pilot Project

As a result of its collaboration with EPRI, PGE deployed the Early Fault Detection (EFD) pilot project in 2021.[13] EFD uses sensors to detect anomalies on the feeder in real time, allowing PGE to intervene (replace or repair) the affected component(s) prior to a failure that could cause an ignition. In 2023, PGE will deploy the first of three planned EFD systems on feeders within its HFRZs and, if possible, will add further EDF systems by leveraging potential federal grant funding opportunities. In addition, in 2023 PGE will evaluate detection/response times for covered conductor equipped with an EFD system to assess the viability of this approach as an alternative to undergrounding within its HFRZs.

Figure 21: Damaged Conductor Identified by EFD System in 2022 and corrected by PGE

[13] Incubatenergy Labs 2020 Pilot Project Report: IND Technology – Early Fault Detection for Power Lines

Figure 22: Example of An Installed EFD System

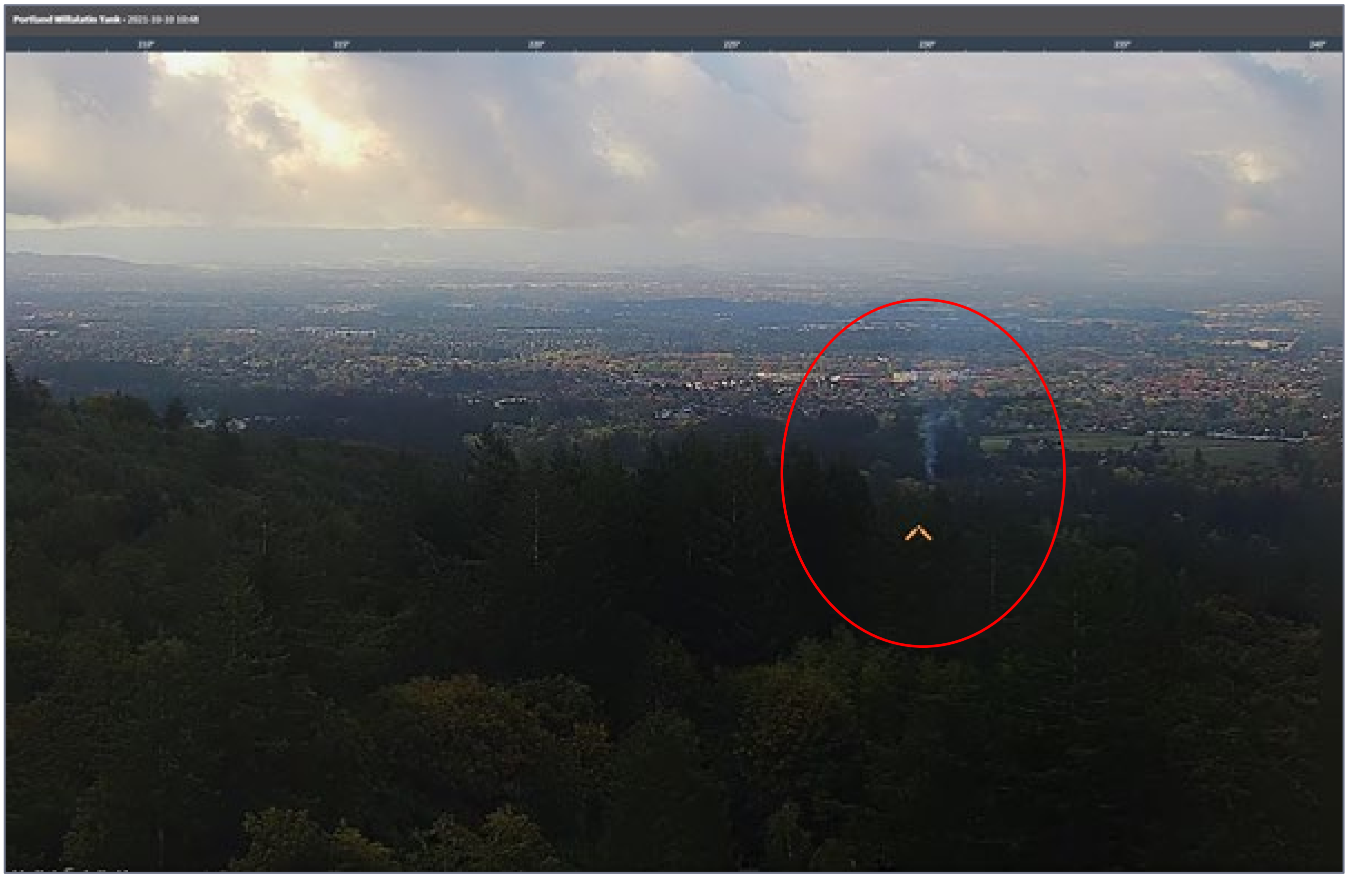


15.2 Pano AI: 360-Degree, AI-Based Imaging

In 2021, in partnership with EPRI and the City of Portland, PGE tested an artificial intelligence-enhanced ultra-high-definition (UHD) camera technology, Pano AI (Incubatenergy Labs 2021 Pilot Project Report – Pano AI – 360-Degree, AI-Based Imaging for Wildfire Situational and Locational Awareness). These cameras can detect and identify smoke through ultra-high-definition video imaging, and notify PGE if it detects a fire, in real time. As the PGE-sponsored pilot project showed, this technology has proven benefits in accelerating fire detection and response times. The cameras are now operational within all PGE HFRZs and detected multiple fires (not wildfires) in 2022.

As of 2022, PGE validated the efficacy of this technology and deployed 22 Pano AI cameras across its 10 HFRZs (see Figure 9 for locations) and plans to deploy an additional 15 cameras in 2023. PGE also provided access to these cameras to multiple Public Safety Partners, including the Columbia Cascade Interagency Communications Center (which provides camera access to USFS, ODF, U.S. Fish & Wildlife Service and other agencies), three ODF Forest Protection Districts, and the Confederated Tribes of Grande Ronde, among others. See Section 7.1, Enhanced Monitoring & Technology In HFRZs, for a full list of agencies with access to PGE's Pano AI network.

Figure 23: Smoke Detected by AI-Equipped UHD Camera



15.3 Remote Sensing Pilot Project

In 2021, PGE conducted a Remote Sensing data acquisition project for its HFRZ feeders, to support wildfire and resiliency preparedness and operational design and engineering work in 2022. The project used various high-tech geospatial imaging technologies (listed below) to provide PGE with a detailed understanding of vegetation risk, clearances to poles and wires, and ROW accessibility within PGE's HFRZs.

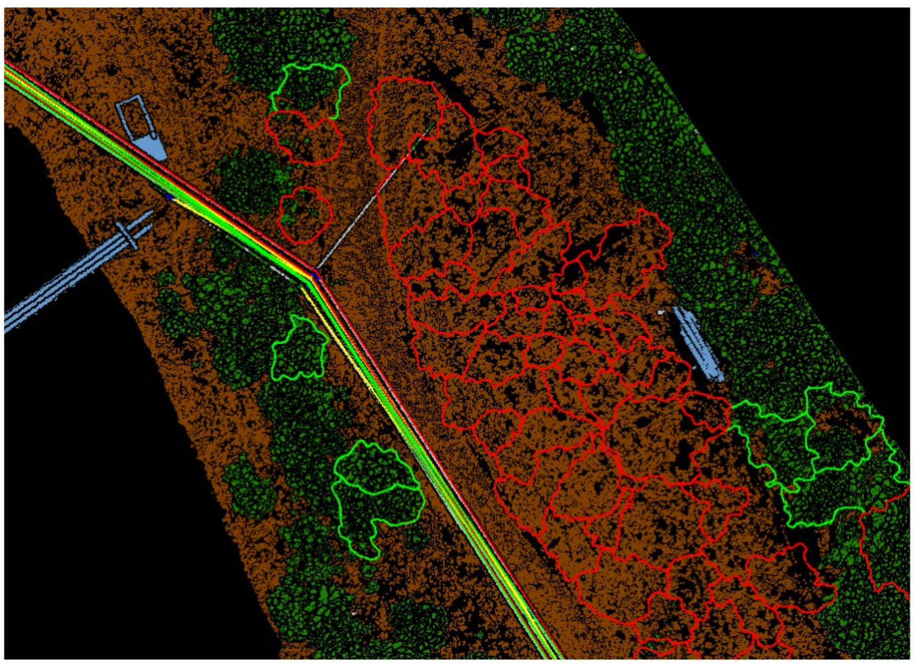
The 2021 HFRZ Remote Sensing Pilot Project produced precise mobile and aerial LiDAR imaging, spherical imagery, and satellite multispectral imagery surveys of 774 circuit-miles of conductor and nearly 15,000 poles within the PGE HFRZs.

This data and analysis have also been taken into consideration in PGE's 2023 capital planning work, which guides its wildfire investment strategy. It will also help PGE understand how much risk has been mitigated through previous years' AWRR (vegetation management) activities and is being used for 2023 vegetation management program planning.

PGE's Remote Sensing Pilot Project also provides:

- GIS-enabled analyses of vegetation clearance and vegetation health
- Consolidated pole/span inventory
- Pole/span change detection analysis (2019-2021)
- Consolidated tree threat inventory (2019 and 2021)
- Tree change detection analysis (2019-2021).

Figure 24: Sample Aerial LiDAR Imagery



Areas outlined in red show trees identified as threats in 2019 that have since been removed.

15.4 Storm Predictive Tool

In late 2022 PGE operationalized a prototype version of a Storm Predictive Tool that will assess wildfire weather risk to PGE equipment using weather data from across the PGE service territory. In 2023, PGE will conduct further model testing and validation to assess the Storm Predictive Tool's ability to incorporate more granular and sophisticated inputs to better inform PGE's PSPS execution decision analysis and improve system alarming.

When initialized in Q4 2023, this tool will significantly improve PGE's ability to predict potential equipment outages based on forecasted and real-time meteorological data. The Storm Predictive

Tool will offer co-benefits to PGE's Utility Asset Management program, including increased spare equipment ordering efficiency, spare equipment mobilization, and operational standards and practices.

15.5 5G PGE Energy Lab

PGE also leads the 5G PGE Energy Lab, focused on the development of innovative wildfire mitigation technologies. The collaboration is evaluating use cases and developing business cases for wildfire-related surveillance, sensing and data collection, and cloud storage technologies, laying the groundwork for the use of artificial intelligence-driven analysis in these disciplines. Through this collaboration group, PGE has been investigating ways to interface the emerging 5G network with Pano AI to explore how greater communications bandwidth can enhance this fire detection technology. Results from the research will guide the deployment of additional Pano AI wildfire cameras across PGE's service territory in 2023.

In September 2022, T-Mobile US announced a partnership with Pano AI and PGE to connect the network of AI-enabled cameras to T-Mobile's powerful and far-reaching 5G system. The partnership will allow PGE and Pano AI to gather high-quality video in at-risk areas and send "vast amounts"[14] of data to Pano AI's command center in real time. This project is especially important in rural and remote areas; the long range of T-Mobile's 5G network will allow the partnership to bring this state-of-the-art fire detection technology to some of the state's most vulnerable locations.

15.6 Proposed Project: Portable Battery Pilot

Based on peer benchmarking learnings from the California utilities, in 2023 PGE proposes to pilot and study a select customer offering of no-cost portable battery devices to provide backup power to PSPS-impacted residential customers also enrolled in PGE's medical certificate program. The purpose of the pilot would be to understand the customers' usage of the battery devices to back up critical medical devices, impacts on feelings of preparedness and resilience, and the customer's experience during an outage prior to and after receiving a device. The budgeted cost to provide a portable battery device to qualified customers and study the impacts for Year 1 is estimated at $100,000. PGE will file a detailed program application for an operational tariff prior to offering this option to customers.

[14] Link to article: [T-Mobile US, Pano AI help detect wildfires with 5G, AI (rcrwireless.com)]

Contact PGE

For information regarding PGE's wildfire mitigation program and wildfire-related emergency kits, plans, checklists, education, and preparedness information, please visit PGE's website (portlandgeneral.com), or call at 1-800-542-8818. Current situational updates, outage status, and wildfire information are also available via social media platforms (Facebook, Twitter, Instagram, and LinkedIn).

15. Revisions Log

The following table details the nature, date, and primary author of major revisions to this document. All impactful revisions—revisions that make significant changes to PGE Wildfire Mitigation strategies—will be described in the Revision Description column.

Date	Version	Revision Description
12/21/2022	1	Issued for implementation by WM&R

Appendices

Appendix 1: Oregon Wildfire Mitigation Rules and 2022 OPUC Independent Evaluator Recommendations In the WMP

Oregon Administrative Rules - Wildfire Mitigation Plans

Oregon Administrative Rule: Chapter 860, Division 300	
Rule Citation	**Where addressed in PGE Wildfire Mitigation Plan**
860-300-0020: **Public Utility Wildfire Mitigation Plan Filing Requirements**	
1(a)	**Section 6.1** (Risk Assessment Overview)
1(a)(A)	**Section 6.1** (Risk Assessment Overview) **Section 7** (High Fire Risk Zones)
1(a)(B)	**Section 6.1** (Risk Assessment Overview) **Appendix 9** (PGE Wildfire Risk Assessment Overview & Process)
1(b)	**Section 6.5** (Wildfire Risk-Based Making)
1(c)	**Section 6.5** (Wildfire Risk-Based Making)
1(d)	**Section 13.4** (Wildfire Community Outreach and Awareness Strategy)
1(e)	**Section 9** (Operation During PSPS Events and Protocols for De-Energization of Power Lines) **Section 9.1** (Power System Operations During PSPS Events) **Section 9.2** (Levels of a PSPS Event) **Section 9.3** (Communication Requirements During PSPS Events)
1(f)	**Section 13.4.2** (Outreach and Awareness Timing) **Appendix 5** (2022 Wildfire Outreach and Awareness Efforts)
1(g)[15]	**Section 10** (Ignition Prevention Inspections)
1(h)[16]	**Section 11** (Vegetation Management)
1(i)	**Section 12** (Wildfire Program Costs)

[15] Utility infrastructure inspection consistent with OAR 860-024-0018
[16] Vegetation management within HFRZs consistent with OAR 860-024-0016

Oregon Administrative Rule: Chapter 860, Division 300	
Rule Citation	**Where addressed in PGE Wildfire Mitigation Plan**
1(j)	**Section 14** (Participation in National and International Forums)
1(k)[17]	**Section 10** (Ignition Prevention Inspections)
2	**Section 1** (Introduction)
3	**Section 1** (Introduction)
4	Not applicable.
860-300-0030: **Risk Analysis**	
1	**Section 6.1 (Risk Assessment Overview) , 6.2** (Updates to the 2023 Wildfire Risk Mitigation Assessment) Appendix 9 (PGE Wildfire Risk Assessment Overview & Process)
1(a)	**Section 6.3** (Wildfire Risk Categories)
1(a)(A)	**Section 6.3.1** (Baseline Wildfire Risk)
1(a)(B)	**Section 6.3.2** (Seasonal Wildfire Risk)
1(a)(C)	**Section 6.3.3** (Risk to Residential Areas)
1(a)(D)	**Section 6.3.4** (Risk to PGE Equipment)
1(b)	**Section 6.2** (Updates to 2023 Wildfire Risk Mitigation Assessment)
1(c)	**Section 6.3.5** (Georisk) **Appendix 9** (PGE Wildfire Risk Assessment Overview & Process)
1(c)(A)	**Section 6.4** (Risk Assessment Methodologies: Data Quality and Review Frequency)
1(c)(B)	**Section 6.4** (Risk Assessment Methodologies: Data Quality and Review Frequency)
1(d)	**Section 6.5** (Wildfire Risk-Based Decision Making)
1(d)(A)	**Section 6.5.1** (Risk-Based Decision Making for PSPS Events)
1(d)(B)	**Section 6.5.2** (Risk-Based Decision Making and Mitigation Actions for Vegetation Management)
1(d)(c)	**Section 6.5.3** (Risk-Based Decision Making and Mitigation Actions for System Hardening)
1(d)(D)	**Section 6.5.4** (Risk-Based Decision Making and Mitigation Actions for Capital Improvements)

[17] Ignition inspection program per OAR 860-024.

Oregon Administrative Rule: Chapter 860, Division 300	
Rule Citation	**Where addressed in PGE Wildfire Mitigation Plan**
1(d)(E)	**Section 6.5.5** (Risk-Based Decision Making and Mitigation Actions for Operations)
2	**Section 6.2** (Updates to 2023 Wildfire Risk Mitigation Assessment)
860-300-0040: **Wildfire Mitigation Plan Engagement Strategies**	
1	**Section 13.3** (2023 WMP Engagement Strategy)
1(a)	**Section 13.3** (2023 WMP Engagement Strategy)
1(a)(A)	**Section 13.3** (2023 WMP Engagement Strategy)
1(a)(B)	**Section 13.3** (2023 WMP Engagement Strategy)
1(b)	**Section 13.3** (2023 WMP Engagement Strategy)
2	**Section 13,.4** (Wildfire Community Outreach and Awareness Strategy)
2(a)	**Section 13,.4** (Wildfire Community Outreach and Awareness Strategy)
2(a)(A)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(a)(B)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(a)(C)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(a)(D)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b)(A)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b)(B)	**Section 13.4.2** (Outreach and Awareness Timing) **Appendix 4** (Inventor of Community Outreach and Engagement Materials and Channels)
2(b)(C)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b)(C)(i)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b)(C)(ii)	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
3	**Section 13.5** (Assessing Effectiveness of Wildfire Community Outreach and Awareness Efforts)
4	**Section 13.6** (Public Safety Partner Coordination Strategy)
4(a)	**Section 13.6.1** (Prior to Fire Season)
4(b)	**Section 13.6.1** (Prior to Fire Season)
4(c)	**Section 13.6.1** (Prior to Fire Season)

Oregon Administrative Rule: Chapter 860, Division 300	
Rule Citation	**Where addressed in PGE Wildfire Mitigation Plan**
860-300-0050: **Communications Requirements Prior, During, and After a Public Safety Power Shutoff**	
1	**Section 9.3** (Communication Requirements During PSPS Events)
1(a)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(A)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(B)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(C)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(D)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(E)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(F)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(G)	**Section 9.3** (Communication Requirements During PSPS Events)
1(b)(H)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)(A)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)(B)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)(C)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)(D)	**Section 9.3** (Communication Requirements During PSPS Events)
1(c)(E)	**Section 9.3** (Communication Requirements During PSPS Events)
1(d)	Not applicable
2	**Section 9.3** (Communication Requirements During PSPS Events)
2(a)	**Section 9.3** (Communication Requirements During PSPS Events)
2(a)(A)	**Section 9.3** (Communication Requirements During PSPS Events)
2(a)(B)	**Section 9.3** (Communication Requirements During PSPS Events)
2(a)(C)	**Section 9.3** (Communication Requirements During PSPS Events) **Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
2(b))	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(A)	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(B)	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(C)	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(D)	**Section 9.3** (Communication Requirements During PSPS Events)

Oregon Administrative Rule: Chapter 860, Division 300	
Rule Citation	**Where addressed in PGE Wildfire Mitigation Plan**
2(b)(E)	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(F)	**Section 9.3** (Communication Requirements During PSPS Events)
2(b)(G)	**Section 9.3** (Communication Requirements During PSPS Events)
3	**Section 9.3** (Communication Requirements During PSPS Events)
3(a)	**Section 9.3** (Communication Requirements During PSPS Events)
3(b)	**Section 9.3** (Communication Requirements During PSPS Events)
3(c)	**Section 9.3** (Communication Requirements During PSPS Events)
4	Not applicable
5	Not applicable
860-300-0060: **Ongoing Informational Requirements for Public Safety Power Shutoffs**	
1	**Section 9** (Operations During PSPS Events)
2	**Section 13.4.1** (Wildfire Communication and Awareness Channels and Campaigns)
3	**Section 9** (Operations During PSPS Events)
4	**Section 9** (Operations During PSPS Events)
860-300-0070: **Reporting Requirements for Public Safety Power Shutoffs**	
1	In the event of a PSPS event, PGE will file with the OPUC, an annual report(s) on de-energization lessons learned, no later than December 31.
2	Non-confidential versions of annual reports filed with the OPUC under this section will be made available on PGE's website.

Appendix 2: PGE Ignition Prevention Inspection Standards

The following checklist is used by PGE's Utility Asset Management organization to ensure a thorough and consistent ignition prevention inspection process for PGE assets.

1	Permanently out of service or abandoned electrical equipment
2	Blocked access roads to supporting structures
3	Abandoned/coiled service wire hanging from pole
4	Broken secondary lashing wire
5	Service/primary neutral touching guy, transformer, or pole
6	Damaged, broken, or frayed power conductor
7	Broken/cut/missing ground
8	Broken communication mainline lashing wire
9	Broken power insulator or tie wire
10	Slack, corroded, or broken power guy
11	Anchor pulled loose/not holding
12	Crossarm brace damaged/broken, missing, or loose
13	Damaged/broken/corroded/loose distribution hardware and connectors
14	Equipment leaking oil—transformer, regulator, etc.
15	Damaged/broken cutout, lightning arrestor, or similar pole-mounted equipment
16	Damper damaged, slipped, or missing
17	Service or conductor attached to tree
18	Midspan horizontal clearance to unattached pole per NESC requirements
19	Missing cotter key, insulator nut, or other line hardware
20	Power hardware, including transmission, not properly grounded/bonded
21	Midspan vertical (pole-to-pole)
22	Midspan horizontal primary (conductor close to building or sign per NESC requirements)
23	Midspan vertical
24	Low transmission or primary conductor close to neutral, secondary or communications or other equipment/conductors per NESC requirements
25	Midspan vertical—power over drivable surface
26	Midspan vertical—power over driveway or pedestrian surface
27	Midspan vertical—communications over drivable surface
28	Overloaded pole
29	Damaged or decayed pole
30	Severely leaning or washed-out pole
31	Vegetation—hazard trees, limbs laying on conductor, impaired clearances to vegetation, tree limbs burning or burned in
32	Crossarm damaged/broken

Appendix 3: Comments Received During PGE's 2022 WMP Engagement Sessions

We Hear You—Customer Feedback

- Customers are both appreciative and frustrated. Some recognize the depth of the plan and appreciate how hard PGE works to get them this information. But others feel ignored and want to know how they can help to improve the outage map.

I did read the entire 65 page report and ***appreciated the depth and detail of the plans documented.*** *Thank you for investing the time and resources to develop it, I look forward to the hard work in the years ahead to put it all into practice.*

My only comment on the PSPS is that ***I wish that communication was more frequent than every 24 hours.*** *It would be preferable to have it at least every 6-12 hours.*

Thank you for the presentation and your work.

I very much appreciate PGE. I realize your challenges are significant. I am frustrated with my current frequent power outages (almost once a month). However, ***I was encouraged about what I learned at the presentation about mitigation steps you are taking to prevent planned power shutoffs and how this could also improve the current (un)reliability of my power.*** *I appreciate PGE's environmental consciousness.* ***You are heads above other power companies I have dealt with.*** *I appreciate your front line folks. Your operators on the phone are pleasant, informative and helpful (and I can be cranky when my power is off since I have to water, no heat, no phone, no septic). Your linemen are super - I know they are working long hours but I have found them to be helpful, cheerful and informative. Thanks for your service!*

I would like to ***know how those of us who live in rural areas could help in reporting*** *obvious power outages and/or line issues we observe before an emergency occurs*

Thank you for doing these events *and having the opportunity to connect with PGE.*

They told me they would call me. Nobody has. Not impressed

As a long time customer, we do not support your strategy to mitigate your liability during infrequent fire weather events that severely hampers rural landowners ability to care for livestock, maintain food safety, personal hygiene, and most importantly protect their homes and outbuildings from fire. ***You are transferring your risk and costs to your customers who have to invest in expensive backup systems to maintain their own safety*** *without your power supply while you reap additional profits by shipping customer power out of state. Your "Public Safety" power redistribution has made me a very unsatisfied customer.*

Communicate more frequently during PSPS. *Every 6-12 hours instead of once every 24 hours.*

Question:
Was there anything you wanted to bring up during the workshop, but you were unable to at the time? Tell us what it was here.

We Hear You—Customer Feedback

- Clarity and preemptive communication are highly important. And the PSPS led to some customer suspicion as to PGE's motives. More communication about the connection between power lines and fires is needed help customers understand the importance of the PSPS.

Just stop doing power outages to limit your liability under the guise of public safety. *If your infrastructure is built and maintained according to PUC standards, there should be no problems, especially when red flag warnings are so broadly forecast with significant variation in actual on the ground weather conditions within the geographic area.* ***Rural customers have no way to protect their property from fire when they lose power to their wells.*** *Communication with customers without power lose internet* ***and cannot do business or receive updates from you via email.***

Being clear about when power would be restored *to those of us who had our power turned off.*

They need to listen to customers. ***They should have listening sessions regarding the psps map.***

I do not want to place all of the blame on PGE as it is clear they made an effort to contact our business. ***I would like to know minimum 1 week prior to the shut off event.*** *This is obviously hard to estimate when dealing with weather.* ***Info on where the resource centers are would be nice.*** *I did not know PGE had created those. Again I will be more attentive now that I know the situation is likely to happen again.*
Perhaps PGE could work in conjunction with The Dept of Land Conservation and Development to establish lower risk areas that include state zoned farm land that did not seem high risk at all.

Our power goes off all the time up here and I am tired of it!!
The power lines should be underground so you don't disrupt so many people!
Is this going to be a constant thing to just turn off our power when the wind blows? ***You're forcing everyone to get a generator, which I would love to have but can't afford!!***

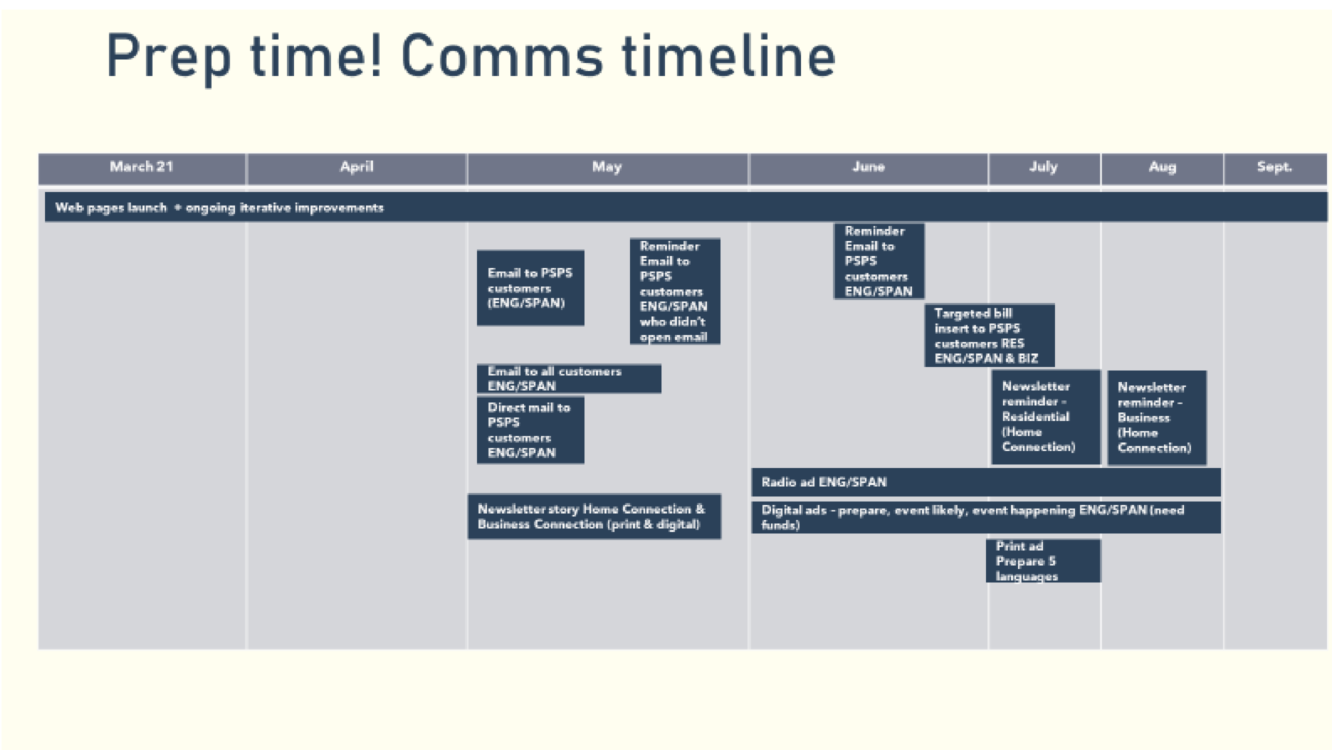
Question:
What would you change or improve about PGE's communications during a PSPS?

Appendix 4: Inventory of Community Outreach and Engagement Materials and Channels (2022)

Channel	Effort/Deliverable	Campaign	Audience	Timing
Stakeholder outreach around new HFRZs with one-pager on wildfire mitigation and HFRZ information	Emails, phone calls, meetings	Wildfire Preparation & PSPS Awareness	All Stakeholders	Dec. 2021
PortlandGeneral.com wildfire and PSPS information	https://portlandgeneral.com/outages-safety/wildfire-outages https://portlandgeneral.com/en-esPanol/apagones-por-incendios-forestal https://portlandgeneral.com/outages-safety/safety/wildfire-safety https://portlandgeneral.com/outages-safety/be-prepared https://portlandgeneral.com/outages-safety/be-prepared/prepare-your-home https://portlandgeneral.com/en-esPanol/prepare-su-hogar https://portlandgeneral.com/outages-safety/be-prepared/prepare-your-business	Wildfire Preparation & PSPS Awareness	Broad awareness	March 2022 through Fire Season
Tool kit in 15 languages that provided preparedness tips and info about PSPS areas	Direct email	Wildfire Preparation & PSPS Awareness	Community-Based Organizations	June 24, 2022
Statewide press release for Wildfire Awareness Month	Press release	Wildfire Preparation	Media, public	May 9, 2022
Public Information Officers (regional and in cities/counties that have PSPS areas)	Toolkit	Wildfire Preparation + PSPS Awareness	Broad public	July 13, 2022
Advertising				
Direct customer communications & PGE newsletters				
Media engagement about wildfire preparedness & PSPS awareness	Interviews and information shared with KGW, KATU, KOIN, KPTV, Oregon Capital Chronicle, Oregon Public Broadcasting, KDRV, KTVZ, Bloomberg, Utility Dive, and others.	Wildfire preparation & PSPS Awareness	Broad public	May through Sept. 2022

Channel	Effort/Deliverable	Campaign	Audience	Timing
Community wildfire preparedness meetings to share preparedness and PSPS information	WM&R presentations at six events focused on wildfire preparedness at the request of government officials and public safety partners. Brochures about wildfire awareness and PSPS were available in English and Spanish.	Wildfire Preparation & PSPS Awareness	Public, customers	May and June 2022
Social media posts about wildfire preparedness and PSPS	Posts on @portlandgeneral on Twitter and @portlandgeneralelectric on Facebook	Wildfire preparation & PSPS Awareness	Public, customers	May through Sept. 2022

Appendix 5: 2022 Wildfire Outreach and Awareness Timeline



Digital ads

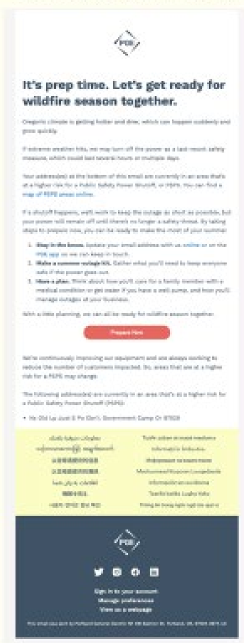
Direct mailing with brochure

Newsletter stories

Reminder bill insert

Print ads in 5 languages

Emails (ENG + SPA)



Web English

Web Spanish

Addtl. info in 13 languages

Wildfire event customer comms

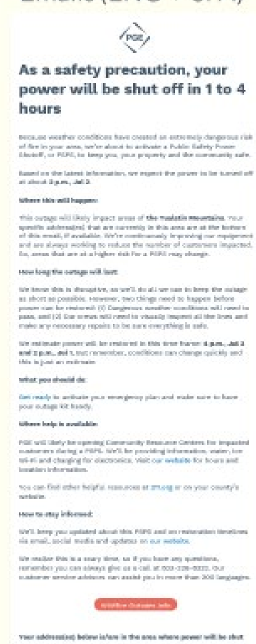
Digital ads - Event likely (ENG + SPA)

Web banner & PSPS active page

SP to screenshot

Digital ads - Event happening (ENG + SPA)

Emails (ENG + SPA)



Expanded details

March – May

- March/April: Web pages (test pages: landing, /prepare, /preparebiz, /wildfireoutages, /psps, /wildfire) live + constant, iterative improvement
- May 10: PSPS letter/DM sent to customers with 4-panel brochure
- May 9 - 20: Email to ALL residential & biz customers, excluding customers in PSPS zone
- May 2 - 6: Email 1 to PSPS customers (RES & BIZ)
- May 23 - 27: Email 2 to PSPS customers (RES & BIZ) who didn't email open

May - September

May 1: Newsletter story in Home Connection & Business Connection

Web pages (test pages: landing, /prepare, /preparebiz, /wildfireoutages, /psps, /wildfire) live + constant, iterative improvement

- Paid and organic social
  - Run through September
- June 1: Radio ads
  - Run through September
  - Streaming targeted: 80% of spend focused on PSPS areas, 20% territory-wide
  - Terrestrial radio, focused on country and oldie stations
- June 1: Digital ads
  - Run through September
  - Targeted: 80% of spend focused on PSPS areas, 20% territory-wide
- June 27-July 11: Reminder email to PSPS customers (RES & BIZ)
- July: Print ads

Web pages (ENG/SPA/Multi lang)

Launch 3/21 with constant, iterative improvement through September

- Prepare landing – Generic landing for residential or business customers, links to preparedness pages and helpful outage information.
- Prepare your home - Educate residential customers about what they need to do to prepare for summer outages.
- Multilanguage page – Educate customers in 13 languages on how to use interactive map, how to prepare and where to get the latest information.
- Prepare your business – Educate general business and key customers about what they need to do to prepare for summer outages.
- Wildfire outages – Educate customers (and media) about wildfire threat and resulting PSPS possibility. Define a PSPS, show map of zones, answer FAQs.
- Wildfire safety - Educate stakeholders (and customers) about wildfire threat & what we're doing to keep they system safe.

Email/Direct Mail/Newsletter story

Email -

May 2 - 6 – PSPS customers – you are in a high-risk area for wildfires, here's how you prepare

- Residential English
- Business English
- Residential Spanish
- Customers with both residential and commercial accounts

May 9 - 20 – All customers – Get prepared for wildfire season

- Residential English
- Residential Spanish
- Business English

May 23-27: Reminder only to customers who didn't open first email – PSPS customers – reminder to get prepared

- Residential English
- Residential Spanish
- Business English

June 27-July 11: Reminder email to all PSPS customers (BIZ & RES)

Direct Mail

May 9 & 10: PSPS customers – you are in a high-risk area for wildfires, here's how you prepare

- PSPS residential customers English
- PSPS residential customers Spanish
- PSPS business customers English
- Customers with both residential and commercial accounts

Newsletter story in Home Connection & Business Connection

May bill cycles – Get prepared (Home Connection & Business Connection)

- Residential English
- Business English

July bill cycles: Reminder newsletter (Home Connection)

Aug. bill cycles: Reminder newsletter (Business Connection)

Targeted bill insert to PSPS customers (RES & BIZ)

- June 15 – July 15: targeted bill insert

Advertising

Digital

- English and Spanish
- June - September
- 80% of spend targeted to PSPS areas, 20% territory-wide

Radio

- English and Spanish
- June - September
- Streaming radio will target 80% of spend on PSPS areas, 20% territory-wide
- Terrestrial radio English, focused on oldie and adult contemporary or country stations
- Terrestrial radio Spanish will play on all stations in local media network, Bustos.

Print (Oregonian, Gresham Outlook, Beaverton Valley Times, Hillsboro News Times, Statesman Journal, El Latino De Hoy, + Chinese/Vietnamese/Other non-English outlets)

- July
- English will target local community papers in PSPS areas
- Spanish will run in largest local Spanish-language publication

Appendix 6: Outcomes of 2022 Outreach and Awareness Efforts

1. Wildfire Webpage Visits (May-September)

- 4,403 sessions to https://portlandgeneral.com/psps-info
- 186,177 sessions to https://portlandgeneral.com/outages-safety/wildfire-outages
- 10,168 sessions to https://portlandgeneral.com/en-esPanol/apagones-por-incendios-forestales10,168 sessions to https://portlandgeneral.com/en-esPanol/apagones-por-incendios-forestales
- 4,689 sessions to https://portlandgeneral.com/outages-safety/safety/wildfire-safety
- 27,962 sessions to https://portlandgeneral.com/outages-safety/be-prepared
- 48,805 sessions to https://portlandgeneral.com/outages-safety/be-prepared/prepare-your-home
- 3,175 sessions to https://portlandgeneral.com/en-esPanol/prepare-su-hogar3,175 sessions to https://portlandgeneral.com/en-esPanol/prepare-su-hogar
- 1,421 sessions to https://portlandgeneral.com/outages-safety/be-prepared/prepare-your-business

2. Newsletter and Email Results

Newsletter

- **Home Connection – goes to 325k+**
  - May – 40% OR; 3.12 Click-to-open rate
  - July – 50% OR; 3.47 Click-to-open rate
- **Business Connection – goes to 12k+**
  - May – 38% OR; 2.8% Click-to-open rate
  - August – 44% OR; 2.4% Click-to-open rate

Email

- **Round 1**
  - In Zone: Early May – 43% OR: 2.9% Click through rate
  - In Zone: Late May reminder – 17% OR; 1.9% Click through rate
  - Not In Zone – 48% OR; 1.4% Click through rate
- **Round 2**
  - In Zone (biz, res (Eng/Span) and biz+res) – 44% OR; 1.7% Click through rate
  - Not In Zone – 49% OR; 1.4% Click through rate

Digital Banner Ads

- *English:*
  - Impressions: 5,179,558
  - Clicks: 6972
  - Click-through rate: 0.13%
- Spanish
  - Impressions: 2,124,270
  - Clicks: 4033

- Click-through rate: 0.19%

Pandora Digital Radio

- English
    - Impressions: 1,721,154
    - Clicks: 2038
    - Click-through rate: 0.19%
- Spanish
    - Impressions: 227,042
    - Clicks: 346
    - Click-through rate: 0.27%

Appendix 7: Toolkit for Community-Based Organizations (CBOs)—Sample Outage Preparedness Messages for Social Media, email, Newsletter and Website Messaging

Toolkit – Wildfire Preparedness

May 2022

Social media posts

English	Hot and dry weather conditions increase the risk of wildfires and the likelihood of safety-related power outages. So, PGE wants you to be prepared. Learn how to stay in the know, create an outage kit and make a plan to keep your family safe at **portlandgeneral.com/prepare.**
Arabic	إن حالات الطقس الجاف والحار تزيد من خطر نشوب الحرائق في الغابات واحتمال انقطاع التيار الكهربائي للسلامة العامة. ولهذا، تود شركة PGE إعدادك لمواجهة ذلك. تعرَّف على كيفية البقاء على علم بالمستجدات، وأنشِئ مجموعة أدوات انقطاع التيار الكهربائي وارسم خطة للحفاظ على سلامة أسرتك عبر موقع **portlandgeneral.com/pspsinfo**.
Chinese (simplified)	炎热干燥的天气条件会增加发生野火的风险，与安全相关的停电的可能性也会增加。所以，PGE 希望您做好准备。在 **portlandgeneral.com/pspsinfo** 上学习如何了解最新情况、如何打造停电工具包以及如何制定家庭安全计划。
Chinese (traditional)	炎熱乾燥的天氣條件會增加發生野火的風險，與安全相關的停電的可能性也會增加。所以，PGE 希望您做好準備。在 **portlandgeneral.com/pspsinfo** 上學習如何瞭解最新情況、如何打造停電工具包以及如何制定家庭安全計畫。
Farsi	شرایط آب‌وهوایی گرم و خشک خطر آتش‌سوزی جنگل‌ها و احتمال قطعی برق مرتبط با ایمنی را افزایش می‌دهد. بنابراین، PGE از شما می‌خواهد آماده باشید. نحوه مطلع ماندن، تهیه کیت لوازم ضروری در زمان قطعی برق و برنامه‌ریزی برای ایمن نگه داشتن خانواده خود را در **portlandgeneral.com/pspsinfo**
Japanese	気候が熱く乾燥していると、山火事のリスクや安全に関わる停電発生の可能性が高まります。そこで、PGEから万が一に備えた準備についてご案内いたします。**portlandgeneral.com/pspsinfo**にアクセスして、ご家族皆様の安全をお守りできるよう、役立つ情報をご確認の上、停電キットを作成してください。
Korean	덥고 건조한 날씨는 산불 위험과 안전 관련 정전 가능성을 높입니다. PGE와 함께 위험에 대비하시기 바랍니다. **portlandgeneral.com/pspsinfo**에서 최신 정보를 파악하고, 정전

	키트를 만들고, 가족을 안전하게 지키기 위한 계획을 세우는 방법을 알아보십시오.
Rohingya	Goróm ar fúwana abaháwar haálot ókkol ólla bouli zoñlor-oin or hótara ar óitfaredé héfazoti-mutalek kaáren bon táka ókkol bari zargoi. Étolla, PGE é oññorare toiyar rákito saár. Zanifuni keengori tákiba, outage kit (kaáren bon tákar saaman) toiyari ar oññor fémelire héfazot rákibar plan ókkol zaniloiyó eçe **portlandgeneral.com/pspsinfo.**
Russian	Жаркие и засушливые погодные условия повышают риск возникновения лесных пожаров и вероятность отключения электроэнергии для обеспечения безопасности. Поэтому компания PGE хочет подготовить вас к этому. С советами о том, как оставаться в курсе событий, подготовить набор необходимых вещей на случай летних отключений электроэнергии и составить план по обеспечению безопасности своей семьи можно ознакомиться на странице **portlandgeneral.com/pspsinfo.**
Somali	Xaaladaha cimilada kulul ee qalalan ayaa kordhinaaya khatarta dabka iyo suurtagalnimada koronto jarista la xariirta badqabka. Marka, PGE waxay doonaysaa inaad diyaar garoowdo. Baro sida aad ku helayso xogtii ugu danbaysay, furo kiishada xogta ee ku saabsan koronto go'a kadibna samayso qorshe aad ku dhawrayso badqabka qoyskaaga adoo galaaya **portlandgeneral.com/pspsinfo.**
Spanish	Los climas cálidos y secos aumentan el riesgo de incendios y la probabilidad de apagones por seguridad. Por eso, PGE quiere que esté preparado. Conozca cómo estar informado, crear un kit para apagones y un plan para mantener a su familia segura en **portlandgeneral.com/prepararse.**
Swahili	Hali ya hewa ya joto na kavu huongeza hatari ya moto wa mwituni na uwezekano wa kupotea kwa nguvu za umeme kwa sababu ya usalama. Hivyo basi, PGE ingependa uwe tayari. Pata maelezo kuhusu jinsi ya kupata taarifa, kuunda zana ya kupotea kwa umeme na kuweka mpango wa kudumisha usalama wa familia yako kwenye **portlandgeneral.com/pspsinfo.**
Vietnamese	Điều kiện thời tiết nóng và khô làm tăng nguy cơ cháy rừng và khả năng cắt điện vì lý do an toàn. Do đó, PGE muốn quý vị chuẩn bị sẵn sàng. Tìm hiểu cách luôn cập nhật thông tin, tạo lập một bộ công cụ phòng khi cắt điện và lập kế hoạch giữ an toàn cho gia đình quý vị tại **portlandgeneral.com/pspsinfo.**

Newsletter or web copy

English	If extreme weather conditions threaten PGE's ability to safely operate the electrical grid, they may need to turn off power to help protect

	public safety. These last-resort safety outages are called a Public Safety Power Shutoffs, or PSPS. No one likes an outage but being prepared makes them a little easier to get through. Find tips at **portlandgeneral.com/pspsinfo.**
Arabic	إذا كانت الظروف الجوية القاسية تهدد قدرة PGEعلى تشغيل شبكة الطاقة الكهربائية بأمان، فيتعيّن عليهم فصل التيار الكهربائي للمساعدة في حماية السلامة العامة. تُعرف عمليات انقطاع التيار الكهربائي لدواعي السلامة التي يتم اللجوء إليها كحلٍّ نهائيٍّ باسمPublic Safety Power Shutoffs (انقطاع التيار الكهربائي للسلامة العامة)، أو PSPS. لا أحد يحب قطع التيار الكهربائي ولكن الاستعداد لذلك يُسهِّل عملية تجاوز تلك الفترة. اطلع على النصائح على **portlandgeneral.com/pspsinfo**
Chinese (simplified)	如果极端天气条件威胁到 PGE 安全运行电网的能力，他们可能需要关闭电源，以帮助保护公共安全。这种停电是最后的手段，被称为 Public Safety Power Shutoffs（公共安全电源关闭），或 PSPS。没有人喜欢停电，但做好准备会让停电不那么难熬。在 **portlandgeneral.com/pspsinfo 上查找提示。**
Chinese (traditional)	如果極端天氣條件威脅到 PGE 安全運行電網的能力，他們可能需要關閉電源，以幫助保護公共安全。這種停電是最後的手段，被稱為 Public Safety Power Shutoffs（公共安全電源關閉），或PSPS。沒有人喜歡停電，但做好準備會讓停電不那麼難熬。在 **portlandgeneral.com/pspsinfo 上查找提示。**
Farsi	اگر شرایط آب‌و‌هوایی غیرعادی توانایی PGE برای اداره ایمن شبکه برق را تهدید کند، ممکن است لازم باشد آنها برای کمک به محافظت از ایمنی عمومی برق را قطع کنند. این قطعی‌های برق با هدف حفظ ایمنی، که آخرین راه‌حل هستند، Public Safety Power Shutoffs (قطعی‌های برق جهت حفظ ایمنی عمومی) یا PSPS نامیده می‌شوند. هیچ‌کس قطعی برق را دوست ندارد، اما آمادگی قبلی پشت سر گذاشتن قطعی برق را کمی آسان‌تر می‌کند. نکات را در **portlandgeneral.com/pspsinfo** پیدا کنید.
Japanese	気候の状況があまりにも過酷でPGEが送電網を安全に操作できない場合は、公衆安全を保護するために電気を停止させていただくことがあります。このような停電は最後の手段となり、Public Safety Power Shutoffs(保護停電公衆安全）またはPSPSとも呼ばれます。停電は誰もが不便を感じるものですが、停電に向けて準備をすることで少しは乗り越えやすくなります。**portlandgeneral.com/pspsinfo**にアクセスして、役立つヒントをご確認ください。
Korean	극한의 기상 조건이 PGE의 안전한 전력망 운영 능력에 위협이 되는 경우, 공공 안전을 보호하기 위해 전력 공급을 중단해야 할 수도 있습니다. 이렇게 안전을 위한 최후의 수단으로서 실시하는 정전을 Public Safety Power Shutoff(PSPS, 공공 안전 전원 차단)라고 합니다. 정전을 좋아하는 사람은 아무도 없지만 미리 준비한다면 좀 더 수월하게 대응할 수 있습니다. 관련 팁은 **portlandgeneral.com/pspsinfo**에서 제공됩니다.
Rohingya	Zodi ódorbaára abaháwar haálot é PGE ír héfazoti kaáren bebosta gorár kaabiliyotire dómkidile, ítara aám maincor héfazot ólla bouli kaáren bon gori fílit fare. Héfazotílla kaáren bon tákede é ahéri mouka íyan ore Public Safety Power Shutoffs (Páblik or Héfazoti Kaáren Bon

	Táka), yáto PSPS bouil hoó. Kiyóu kaáren no tákare fosón no gore kintu toiyar tákile cómoi iín faráite asán ó. Mocuwara ókkol tuwai so eçe **portlandgeneral.com/pspsinfo.**
Russian	Если ввиду экстремальных погодных условий компания PGE не может гарантировать безопасность эксплуатации электрической сети, компания может быть вынуждена отключить электроснабжение для обеспечения общественной безопасности. Такие крайние меры в виде аварийных отключений называются Public Safety Power Shutoffs (отключения электроэнергии для обеспечения общественной безопасности) или PSPS. Никому не нравятся подобные отключения, но их легче пережить, будучи готовым. Больше советов по ссылке **portlandgeneral.com/pspsinfo.**
Somali	Haddii xaaladaha cimilada daran ay khatar gashaan awooda PGE ee ku shaqaynta si amaan ah qalabka korontada, waxay u baahan karaan inay damiyaan korontada si loo dhawro badqabka dadwaynaha. Koronto jaristaan ah talaabada ugu danbaysa ee badqabka ayaa loogu yeeraa Public Safety Power Shutoffs (Koronto Jarista Badqabka Dadwaynaha), ama PSPS. Ma jiro qof jecel koronto goyn laakiin inaad u diyaar garoowdo ayaa yaraysa niyad jabka hadhoow imaan kara. Tilmaamo ka fiiri **portlandgeneral.com/pspsinfo.**
Spanish	Si, debido a condiciones meteorológicas extremas, se ve afectada la capacidad de PGE para operar la red eléctrica de manera segura, cortaremos la energía para contribuir a la protección de la seguridad pública. Estos apagones se realizan como último recurso de seguridad y se denominan Public Safety Power Shutoffs (Interrupciones del Suministro Eléctrico por Motivos de Seguridad Pública) o PSPS. A nadie le gustan los apagones, pero estar preparado hace que sean un poco más fáciles de sobrellevar. Encuentre consejos en **portlandgeneral.com/prepararse.**
Swahili	Ikiwa hali mbaya ya hewa inatishia uwezo wa PGEwa kuendesha gridi ya umeme kwa usalama, wanaweza kuhitaji kuzima nguvu za umeme ili kusaidia kulinda usalama wa umma. Hatua hii ya mwisho ya kupoteza umeme inajulikana kama Public Safety Power Shutoffs (Kuzima Umeme kwa Sababu ya Usalama wa Umma), au PSPS. Hakuna mtu anayependa kupotea kwa umeme lakini kuwa tayari kunarahisisha kidogo kukabili hali hii. Pata vidokezo kupitia **portlandgeneral.com/pspsinfo**.
Vietnamese	Nếu điều kiện thời tiết khắc nghiệt có nguy cơ làm trở ngại khả năng của PGE trong việc vận hành an toàn mạng lưới điện, công ty có thể cần cắt nguồn điện để giúp bảo vệ an toàn công cộng. Các biện pháp an toàn cuối cùng bằng cách cắt điện này được gọi là Public Safety Power Shutoffs (Cắt Điện Vì An Toàn Công Cộng), hay PSPS. Không ai thích rơi vào tình trạng mất điện nhưng việc chuẩn bị sẵn sàng sẽ giúp họ vượt qua điều đó dễ dàng hơn một chút. Hãy xem các lời khuyên tại **portlandgeneral.com/pspsinfo.**

PIO Toolkit

July 2022

PGE Wildfire + PSPS Toolkit

Overview

Portland General Electric (PGE) is preparing for the 2022 Wildfire Season and the possibility of proactive Public Safety Power Shutoffs (PSPS) as a tool to help protect lives and property—like we did in the Mt. Hood corridor during the September 2020 wildfires that swept across Oregon.

This year, parts of 10 areas in communities we serve are at higher risk for Public Safety Power Shutoffs, including:

1. Mt. Hood Corridor/Foothills
2. Columbia River Gorge
3. Oregon City
4. Estacada
5. Scotts Mills
6. Portland West Hills
7. Tualatin Mountains
8. North West Hills
9. Central West Hills
10. Southern West Hills

A map of those PSPS areas is at portlandgeneral.com/wildfireoutages. That page is available in English and Spanish and includes a link to portlandgeneral.com/psps-info for information and brochures about wildfire preparedness and information about PSPS's in Arabic, Burmese, Chinese (simplified and traditional), Farsi, Japanese, Korean, Romanian, Rohingya, Russian, Somali, Swahili, and Vietnamese. Our customer service advisors can also assist customers in 200+ languages.

While we have sectioned off our system to reduce the number of customers who may be impacted by a PSPS, and we are communicating broadly and directly to all who may be impacted, we would appreciate your help encouraging communities to plan and prepare.

You may use the information below on your website, in newsletters and on your social media channels. In the event that we experience extreme weather conditions that may lead to a PSPS, PGE will share information over numerous channels, including via portlandgeneral.com, PGE's social media channels, through FlashAlert and outreach to PIOs, Public Safety Partners and media in affected areas.

If you have any questions about these materials or want to make sure you're on our PIO contact list, please contact PGE via PGECommunications@pgn.com.

Wildfire Brochure

You may print and share the document attached to your email titled *PGE 2022 Wildfire + PSPS One Pager May* or post it on your website. It provides an overview of PGE's year-round focus on wildfire protection and steps customers can take to get prepared. It also includes an explanation of Public Safety Power Shutoffs, when they are called and what to expect.

Web Copy

As Oregon's weather gets hotter and drier, the possibility of wildfires and a Public Safety Power Shutoff is increasing. If you're a PGE customer, learn how to stay in the know, make a summer outage kit and a plan. Check PGE's interactive map to see if your home or business is in an area where PGE may proactively shut off power to protect public safety. Visit portlandgeneral.com/wildfireoutages.

Newsletter Copy

Hot and dry weather could lead to a Public Safety Power Shutoff, or PSPS.

As Oregon's weather changes, the summer months bring increased risk of fires. Everyone has a role to play when it comes to being prepared. If you're a PGE customer:

- ***Stay in the know*** *by updating your email address and phone number on your PGE account so they can stay in touch in the event of an outage.*
- ***Create an outage kit*** *by gathering what you'll need to keep employees, customers and your family safe if power goes out. Make sure your employees and family members know where to find it.*
- ***Make a plan*** *to keep your business or family safe during an outage, especially if a medical condition or water for livestock or crops requires electricity. Know where you'll go if you need to relocate.*

Social Media Copy

PGE is posting wildfire preparedness information on Twitter (@PortlandGeneral), Facebook (@PortlandGeneralElectric) and Instagram (@PortlandGeneral). Posts are available in English and Spanish.

Please use the links below to retweet on Twitter, share on Facebook and/or share to your organization's stories on Instagram. Feel free to tag us!

Also, please note that in the event we call a PSPS, we will share updates on Facebook, Instagram and Twitter and would appreciate your amplification.

Social Posts to Amplify

Please consider liking and sharing these posts on Facebook, retweeting PGE posts and sharing PGE posts as Instagram stories.

- Post on 5/11: Summertime means Prep Time! Fire Season is here – now is the time to start thinking about the proactive steps you can take to best prepare for the potential of wildfire and corresponding power outages. Learn more: bit.ly/3F4nbCm

  Twitter:
  https://twitter.com/portlandgeneral/status/1524426615660453889?s=20&t=1Bbyv8rEtWnO-vdG2_kh4w
  Facebook:
  https://www.facebook.com/PortlandGeneralElectric/posts/5873100286050493
  Instagram: https://www.instagram.com/p/CdbK1tguYks/?utm_source=ig_web_copy_link

- Post on 5/18: As Oregon's weather gets hotter and drier, wildfires can hit suddenly and grow quickly. NOW is the time to confirm your contact information is up to date in our system so that we can alert you ahead of, and throughout, potential wildfire outages.

  Twitter:
  https://twitter.com/portlandgeneral/status/1526963325371826176?s=20&t=1Bbyv8rEtWnO-vdG2_kh4w
  Facebook:
  https://www.facebook.com/PortlandGeneralElectric/posts/5893798357314019

- Post on 5/25: When wildfires hit and electricity outages occur, what's your plan? With a little planning, we can all be ready for Wildfire Season together.

  Twitter: https://twitter.com/portlandgeneral
  Facebook: https://www.facebook.com/PortlandGeneralElectric
  Instagram: https://www.instagram.com/portlandgeneral/

- Post on 6/1: For us, being prepared is a year-round effort to protect people, property, and natural environments. Our crews regularly inspect our poles and equipment and make necessary modifications or replacements to reduce the risk of a spark.

  Twitter: https://twitter.com/portlandgeneral
  Facebook: https://www.facebook.com/PortlandGeneralElectric
  Instagram: https://www.instagram.com/portlandgeneral/

Next Steps

As we move through Wildfire Season, additional toolkit content may be shared. Please reach out to PGECommunications@pgn.com if you have questions or need additional information and resources. We appreciate your help getting information out and raising awareness!

It’s fire season. Be prepared.

Oregon’s climate is getting hotter and drier, and that means wildfires can hit suddenly and grow quickly. If extreme weather conditions make it unsafe to keep our equipment on, we may need to turn off the power as a last-resort safety measure.

These outages, also known as a **Public Safety Power Shutoff (PSPS)**, could last several hours or multiple days, so it’s important to be prepared.

> You can find a map of areas that are at higher risk for safety-related outages at **portlandgeneral.com/wildfireoutages**.

Here’s how you can prepare:

1 **Stay in the know** by updating your email on your PGE account so we can send you notices in the event of a safety-related outage.

2 **Create a summer outage kit** and make sure everyone in your home knows where to find it.

Some basic items include:

- Emergency phone numbers, including PGE Customer Service: 503-228-6322

  Our customer service advisors can assist you in 200+ languages.
- Flashlights or headlamps
- Battery-powered or hand-crank radio and clock or watch
- Battery-powered or hand-held fans
- Extra batteries
- Car chargers for cell phones, laptops and/or tablet computers
- Bottled water for people and animals (if you rely on electricity to pump water)
- Frozen cold packs or water frozen in bags or plastic bottles (keep ready in your freezer)

3 **Make a plan** to keep your family and your home safe during an outage.

- Plan ahead to relocate with a friend, family member or to a shelter, especially if you have a medical condition that requires electricity or if you’ll need to work or learn from home during an outage.
- Plan for medical needs so you can still power medical equipment during an outage and consider enrolling in our Medical Certificate program. This will help us proactively communicate with you about outages. Visit **portlandgeneral.com/medical** or call 503-612-3838 to learn more about the program.
- Consider buying a backup generator and follow manufacturers’ guidelines for its safe operation.
- Plan for feeding and watering pets or livestock if you rely on an electric pump for water.
- Get more information from your county’s website or the **National Fire Protection Association**, the **Red Cross** and **Ready.gov**.

Find additional tips on how to get prepared at **portlandgeneral.com/prepare**.

Appendix 8: Summary of Input from Public Safety Partners and Lessons Learned Captured During the 2022 Fire Season

The following improvement plan includes a set of recommendations for identified actions that are based on observations presented in PSPS Tabletop AAR, Public Safety Partners communication conference calls, and September 2022 PSPS AAR. As appropriate, these actions have been incorporated throughout the 2023 WMP.

Core Capability	Objective ID	Objective
Public Information and Sharing	A	Identify what sequential and iterative notifications need to be made, the process to be taken, and who will support notifications.
	B	Identify customer communications needs and conduct appropriate stakeholder outreach.
Operational Coordination	C	Determine how the Corporate Incident Management Team (CIMT) is activated and structured.
	D	Identify key points of coordination with jurisdictional Emergency Operations Centers (EOCs).
Intelligence and Information Sharing	E	Identify what data and information are required to support decision making including identification of specific information and data products.
Operational Coordination	F	Identify primary and alternate means of communicating with internal and external partners.
	G	Identify communications/data management failure points with limited or no redundancy that could lead to failures in informing customer information needs.

Recommended actions that have been added are:

Objective ID	Opportunities for Improvement	Recommended Actions
D	Confusion in difference of communications between emergent, PSPS, restoration, etc.	Designate specific communications for Preventative Outage Area initiation, PSPS, and restoration.
D, F	Need for enhanced coordination with external partners to identify required information and updates needed during a PSPS.	Create unique templates for critical Public Safety Partners with partner input.
G	Public Safety Partners asked to expand the socialization of the PSPS plan with external partners.	Develop and socialize external facing PSPS plan elements (e.g., PSPS Bell Curve) that can be aligned with or incorporated into Public Safety Partner operational plans.

Objective ID	Opportunities for Improvement	Recommended Actions
A	Public Safety Partners identified need to coordinate timing of messaging to minimize confusion and the impact of other emergency alerts.	Coordinate with public safety partners to align notification procedures including cadence of notifications and use of mass notification systems.
All	Internal and External observations regarding vocabulary and acronym confusion.	Formalize a shared vocabulary within internal and external partners to ensure consistent messaging.
A, B	Establish and socialize triggers signaling PGE staff to send updates to Public Safety Partners	Document list of triggers to send updates to public partners to include with PSPS Playbook and NEP Tracker.
E	PGE acknowledged it is helpful when customer resource centers publicize hours of service.	Coordinate with public safety partners around messaging provided at facilities providing assistance to impacted populations (e.g., cooling centers) to support consistency and alignment of messaging
D	Align PSPS response, with cadence of communications withing the CIMT structure.	Align PSPS response in PSPS Playbook and with reference to the timing a news cycle.

The following table summarizes Lessons Learned from the September 2022 PSPS event in PGE's service territory:

Strengths	
Crisis Communications	PGE demonstrated a sincere commitment to communicate and coordinate with external partners.
Whole Community	Stakeholder communications were robust and comprehensive
	On-the-fly adjustments to community support strategies were effective
	Working collaboratively with PGE, some counties stood up their own CRCs at public locations, while PGE donated supplies to these locations for distribution to impacted communities
Operations	Additional recloser installations prior to the event enabled PGE to reduce the September 2022 PSPS event's customer impacts
	The expanded (for 2022) network of PGE weather stations provided an accurate view of meteorological conditions closer to PGE infrastructure when compared to other weather stations in the regional network
Community Resource Centers	Customers were grateful that PGE was present—CRCs are invaluable during PSPS events and a positive expression of PGE's care for the community

Opportunities for Improvement	
Crisis Communications	Advise and support Public Safety Partners to host a workshop to clarify cross-jurisdictional coordination responsibilities for alerts and warnings.
	PGE and Public Safety Partners should evaluate the use of WEA for PSPS events and define policies and agreements to facilitate its successful and beneficial deployment and reduce "overspray" confusion for notification recipients
Operations	Define additional internal controls for PSPS Areas to more precisely align appropriate PSPS boundaries and actual outage areas.
	Invest in additional tools and equipment to allow more targeted and automated control of PSPS Areas
	Update PSPS Area data to include all critical facilities with consideration for seasonality such as back-to-school dates.
	Designating additional Preventive Outage Areas, in real-time, created communications, operational, logistical and community support challenges.
	During future PSPS events, Ops will use QEWs for patrol crews; field weather observations, however, could be conducted by classifications other than QEWs.
	Cutsheets should be finalized as far as possible in advance of the PSPS event and should be named by feeder and by HFRZ. During the September 2022 PSPS event, crews had to do a lot of sorting through the cutsheets to identify the feeders that needed to be de-energized for each zone; each cutsheet should include a list of feeders within the HFRZ
Whole Community	Establish and document clear lines of responsibility between PGE and Public Safety Partners for CRCs, locations and information sharing.
	Evaluate the use of Wireless Emergency Alerts for PSPS events, with our Public Safety Partners, to reduce "overspray" confusion for notification recipients.
	Assess options to improve the PSPS map functionality and simplify the customer experience
Community Resource Centers	Review site locations using updated criteria and finalize contracts for all locations.
	Formalize CRC volunteer strategy, templates, and training.
	Supplemental employees signed up and trained in advance of the PSPS event.
	Renew contract with CRC vendor for 2023 wildfire season.
	Incorporate vendor recommendations into contract.

	Plan prior to fire season for worst-case scenario – identify CRC locations and ensure that adequate MRUs and supplies are available even if all 10 HFRZs are impacted by a PSPS event

Appendix 9: PGE Wildfire Risk Assessment Overview & Process

PGE consults with wildfire risk experts to model fire behavior while also benchmarking its risk methodology/modelling and data with local and international wildfire programs. Key terms in this process are identified below.

Ignition Potential Index

The Ignition Potential Index (IPI) is a relative measure of the propensity for weather conditions and fuel characteristics at a given location to result in a utility-related wildfire ignition that escapes initial suppression efforts to become a large and potentially damaging fire. PGE models the potential for a wildfire ignition as a function of wind speed, fuel dryness, and heat per unit area, using a model patterned after the California Public Utilities Commission's electric utility Ignition Index and Utility Threat Index. The model derives its base weather observations from gridMET, a historical 4-km resolution, gridded daily weather dataset; PGE applies downscaling and bias-correction algorithms to increase model precision and weather data accuracy. The following sections provide additional details regarding the weather factors considered in PGE's Ignition Potential Index model.

Wind Speed

PGE explored the use of two gridded historical wind speed datasets (gridMET and National Renewable Energy Laboratory (NREL)) in its Ignition Potential Index model. Neither dataset alone was sufficiently detailed to allow PGE to determine the influence of wind speed on the potential for a utility-caused ignition to result in significant fire damage. The gridMET dataset provides detailed daily wind speed grids but includes bias on annual timescales relative to other national products with finer spatial resolutions. PGE corrected this bias using the NREL annual mean wind speed dataset (Draxl et al. 2015) by deriving a daily calibration factor from the overlapping time periods of the two datasets (2007-2013). This approach allows the model to coordinate wind speed and dryness observed in gridMET using the precision of the NREL dataset. The bias correction factor was derived by dividing the mean annual NREL wind speed by the average annual gridMET wind speed during the overlapping time periods. This factor was then applied to daily gridMET wind speeds.

Schroeder Probability of Ignition

Schroeder Probability of Ignition ([SPI], Schroeder 1969) is a long-established measure of the likelihood that a competent ignition source will result in a fire start. SPI is a function of fuel temperature and moisture content. By making some simplifying assumptions, PGE calculates SPI from air temperature and relative humidity, both of which are standard weather variables included in historical summaries and weather forecasts (such as gridMET), and both can be adjusted adiabatically (occurring without loss or gain of heat) for elevation.

Heat Per Unit Area

Heat per unit area (HPA) is a measure of the heat content of the fuelbed (kJ/m2). For surface fuels, HPA is largely a function of the surface fire behavior fuel model (fuel loading by size class and component). For crown fires, HPA also includes the proportion of canopy fuel expected to be involved in a fire.

For a given fuel complex, HPA varies with wind speed and fuel moisture content. PGE classified each day in the record into one of 27 weather types, then computed Daily HPA using a proprietary version of the FlamMap fire modeling system as a function of each cell's fuel characteristics and weather type.

During wildfire events, higher HPA values manifest in greater flame length and increased resistance to firefighter control. HPA can vary by several orders of magnitude. PGE's IPI model takes the square root of HPA to obtain an estimated flame length (flame length is roughly the square root of fireline intensity).

Conditional IPI

Conditional Ignition Potential Index (cIPI) provides PGE with a modeled representation of expected IPI for each weather type studied. The daily IPI dataset provides an assessment of fire potential based on historical observations; however, not all potential weather conditions were represented for each location in the analysis area. PGE therefore created a set of Ignition Potential indices applicable for future weather observations organized by the weather-type classification used throughout this analysis.

PGE applied this general IPI calculation with the following customizations: To calculate localized wind speed, PGE applied the downscaling factors developed to calibrate predominant winds to local, terrain-influenced wind speeds at the mid-point wind speed of each weather type. PGE calculated a mean SPI for each fuel moisture class using the daily historical record. For moisture classes with fewer than 50 observations in the historical record, PGE incorporated the SPI observations of the nearest moisture class to increase the sample size. This was necessary primarily in the northwest corner of the analysis area, where the driest moisture types rarely, if ever, occur in the historical record. PGE applied the same supplemental data approach to model the mean Large Fire Probability (LFP) for each moisture class as well.

Weather Type Probabilities

Weather type probabilities (WTP) are a set of weighting factors derived from the IPI within each weather type relative to the total IPI for a given raster cell. Rasters are matrices of cells organized into rows and columns or grids, where each cell contains a value representing information, such as temperature. Rasters are often displayed as data layers along with other geographic data on maps or used as the source data for spatial analysis.

WTPs integrate the relative ignition potential for that weather type and its relative frequency within the observed record. A weather type with high wind speed, high SPI, etc. will receive a high weighting according to the larger IPI value, but weather types with lower IPI values may also receive a higher weighting if they occur at high frequency.

Spatial Resolution

PGE used downscaling and smoothing to achieve a final cell resolution of 120 meters x 120 meters (3.56 acres). The fuel layers necessary for HPA are available at a 30-meter resolution. To resolve the spatial resolution issue, PGE resampled (using bilinear interpolation, a statistical method by which related known values are used to estimate an unknown value, using other established values located in sequence with the unknown value) the 30-meter HPA estimates for each of the 27-wind speed and fuel moisture combinations to the coarser resolutions of 120-meter and 4-kilometer (depending on the data set).

Smoothing

Data smoothing uses an algorithm to remove "noise" from a data set, such as one-time outlier data points, to allow important patterns to stand out and help the user predict trends. This relatively standard process allows PGE to resample coarse raster cells to a finer resolution—for the IPI model, from 4-kilometer (gridMET native resolution) to 120-meter. PGE used an additional custom process to remove any visible artifacts of the original 4-kilometer resolution, to maintain the fidelity of the synoptic weather processes seen in the gridMET data while achieving spatial coherence with the other provided data products at the 120-meter resolution.

For WTP, the smoothing process included a re-normalization to verify the results and ensure that the weighting factors were still valid (a fraction of the total IPI and therefore all WTP values still summed to one for a given raster cell).

Downscaling

To assess the local effects of topography on weather, PGE downscaled gridMET weather data using adiabatic[18] relationships of elevation to temperature and humidity and modeled the local topographic effect on prevalent wind direction and speeds. For each 120-meter x 120-meter cell and day in the record, PGE adjusted the observed gridMET temperature by the relative difference in elevation between the gridMET 4-kilometer cell and the finer 120-meter cell. This also changed the relative humidity at the 120-meter cell under the assumption that the same absolute water content in an area persisted under variable elevation and temperature.

To assess localized wind speeds, PGE used the WindNinja modeling system (a fluid dynamics physics model that accounts for the effects of topography on wind speed and direction) to run simulations with the prevalent wind at the eight cardinal (indicating the numerical value) and ordinal (indicating the position of the value in a series) directions. This produced eight factors that modified the 4-kilometer wind speed to show the local effects of terrain at the 120-meter resolution. For each day in the record, PGE classified the wind direction to the nearest corresponding factor and adjusted the wind speed to produce a terrain-adjusted wind speed estimate at 120-meter resolution. After

[18] "Adiabatic" refers to a process in which no heat transfer takes place.

downscaling the temperature, humidity, and wind speed, PGE then calculated daily IPI at a 120-meter resolution.

Conditional Impact

Conditional Impact (CI) is a measure of the relative impact of a wildfire (i.e., loss), given that a fire has occurred. CI is a function of fire growth potential and the vulnerability of assets and resources in the area around potential source locations. Fire growth potential is a function of fuel, weather, and topography. Vulnerability is a function of the exposure and susceptibility of homes, resources, and assets across the landscape where the fire occurred.

Unlike IPI, CI does not lend itself to a deterministic (models that produce the same exact results for a particular set of inputs) mathematical solution. To generate CI, PGE applies fire growth modeling to specific ignition locations, then ties the spatial data within the final simulated perimeters back to the ignition location. After generating the final fire-perimeter event set, PGE's model overlays each simulated wildfire with spatial data representing the impacts of wildfire—conditional losses associated with high-value resources and assets.

PGE generalized the event-set results to produce a CI raster at 120 m that represents the tendency for fires originating in that area to impact resources and assets. Thus, PGE was able to model the potential for a wildfire to result in an urban conflagration (such as the 2020 Almeda Fire in Ashland) by including burnable urban fuel models within the appropriate weather types.

Wildfire Simulation

PGE conducted wildfire simulation modeling using the Minimum Travel Time (MTT) algorithm, called Randig. Randig models short duration burn periods under constant weather conditions, assuming no suppression effects. This assumption is appropriate for modeling extreme wildfire spread events, where fire weather and fire behavior can overwhelm suppression resources. PGE applied the Randig algorithm in iterative runs using the 216 unique weather types and other parameters shown in Table 2 (weather types were derived from gridMET weather data as described above).

The following table shows example inputs for the 216 weather types included in PGE's IPI model. Each set of parameters is repeated for each of the eight cardinal direction wind bins (0, 45, 90, 135, 180, 225, 270, 315), yielding a total of 216 unique weather types. These wind speeds are banded in 9 groups of 5 mph increments.

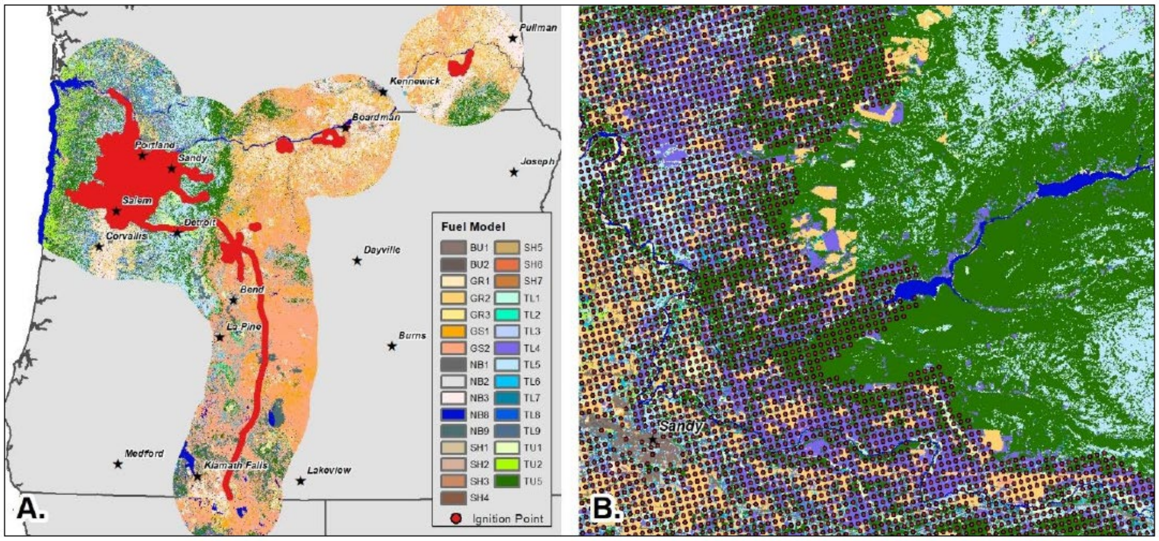
Example PGE Weather Types IPI Model Inputs

20-ft Wind Speed (mi/hr)	MC Class	1-hr MC	Live Herb MC	Live Woody MC	Duration (min)	Spot prob	Burnable Urban?
1	very dry	3%	45	80	60	10%	N
1	dry	5%	60	90	60	0%	N
1	moderate	8%	90	100	60	0%	N
5	very dry	3%	45	80	120	30%	N
5	dry	5%	60	90	120	15%	N
5	moderate	8%	90	100	120	0%	N
10	very dry	3%	45	80	180	50%	N
10	dry	5%	60	90	180	35%	N
10	moderate	8%	90	100	180	20%	N
15	very dry	3%	45	80	240	70%	Y
15	dry	5%	60	90	240	55%	N
15	moderate	8%	90	100	240	40%	N
20	very dry	3%	45	80	300	80%	Y
20	dry	5%	60	90	300	65%	Y
20	moderate	8%	90	100	300	50%	Y
25	very dry	3%	45	80	375	85%	Y
25	dry	5%	60	90	375	70%	Y
25	moderate	8%	90	100	375	55%	Y
30	very dry	3%	45	80	450	90%	Y
30	dry	5%	60	90	450	75%	Y
30	moderate	8%	90	100	450	60%	Y
35	very dry	3%	45	80	525	95%	Y
35	dry	5%	60	90	525	80%	Y
35	moderate	8%	90	100	525	65%	Y
40	very dry	3%	45	80	600	100%	Y
40	dry	5%	60	90	600	85%	Y
40	moderate	8%	90	100	600	70%	Y

The modeled weather types were further downscaled within each wildfire simulation by running Randig with both WindNinja and fuel moisture conditioning functionality. PGE used pre-calculated WindNinja grids representing terrain-adapted wind speed and direction, generated at 120 m resolution, and then up-sampled to 30 m resolution as inputs to Randig. The model applied 10 adjusted moisture contents to individual cells based on canopy cover and topography (slope and aspect).

PGE then applied the Randig algorithm to a lattice grid of ignition points across the analysis area, generating a 270 m grid of ignition points based on a one-kilometer buffer of PGE features within the analysis area. PGE removed certain points based on burnability characteristics; the resulting analysis yielded a total of 84,749 wildfire ignition points for simulation. Figure 4, below, depicts the overall extent of the wildfire simulation ignition points (Panel A) and a detailed view of the ignition lattice (Panel B) near the community of Sandy, Oregon. The red areas in the left-hand panel (left) show the general location of where ignition points are concentrated.

Figure 4: PGE Wildfire Simulation Modeling Results – Potential Ignition Points



PGE simulated each ignition point using each of the 216 weather types described above, at a 90m resolution, resulting in a total of 18,305,784 simulated fires. Modeling wildfire ignition potential at such a fine-scale resolution across such a large area is a computationally intensive exercise, occupying a series of Windows 10 machines with 48-thread CPUs for nearly 3,600 machine-hours.

Highly Valued Resources and Assets (HVRA) Impact Raster

PGE updated the Conditional Net Value Change (cNVC) or "Impact" raster using data produced originally for the Pacific Northwest Quantitative Wildfire Risk Assessment (PNRA)1. PGE adjusted response functions used in the PNRA assessment to remove the beneficial effects of fire, replacing positive values with zero. The final list of Highly Valued Resources and Assets (HVRA) includes (but is not limited to) People and Property, Timber, Wildlife, Infrastructure, and Surface Drinking Water.

All data inputs, including response to fire and relative importance weights, were leveraged from PNRA1, with one exception: the dataset and methodology used to represent housing-unit density was updated in the People and Property HVRA to use the Housing-Unit Density (HUDen) data built for the Wildfire Risk to Communities Project (Scott et al. 2020). This dataset uses population data at the census block level and Microsoft Building footprints to allocate people and homes spatially within a census block.

Additionally, to account for the potential for wildfire spread into urban areas (mapped by LANDFIRE[19] as non-burnable), PGE used an iterative smoothing process to spread distributions of flame-length

[19] LANDFIRE (Landscape Fire and Resource Management Planning Tools), is a shared, government-developed program used by the wildland fire management programs of the U.S. Forest Service and U.S. Department of the Interior, that uses landscape-scale geospatial products to support cross-boundary planning, management, and operations.

probabilities into non-burnable land cover (other than open water or ice) within 1.5 km of contiguous, burnable land cover at least 500 ha in size. These areas would otherwise have a zero probability of burning in the fire model (FSim). This allowed PGE to recalculate cNVC using response functions and relative importance values assigned by the PNRA1 project, while accounting for wildfire spread into urban areas.

Finally, PGE applied a fractional exposure value based on the distance from the burnable fuel (the source of exposure) to account for the decreased exposure of housing units within the 1.5 km distance from burnable fuel. PGE adjusted housing-unit density exposure by multiplying HUDen by the exposure mask value in each pixel. The final People and Property HVRA included housing units directly exposed to wildfire (located in burnable pixels) as well as those indirectly exposed to wildfire (within a 1.5 km distance of burnable fuel).

PGE applied these modified response functions to all other HVRA cNVC layers; the layers were otherwise unaltered from the PNRA1 project. The final cNVC map (summed for all HVRA) serves as the impact raster necessary for the spatial intersection with the simulated fire perimeters—it provides the key to unlocking and understanding the HVRA impact simulations.

Impact Raster Overlays

PGE ran an overlay script to sum the total cNVC within each simulated wildfire perimeter. The total cNVC reported within each perimeter (including spot fires) was attributed back to the original ignition location. This allowed PGE to apply cNVC values (representing the estimated HVRA impacts for each of the 216 modeled weather conditions) to each of the original 84,749 modeled (simulated) ignition points.

Rasterization

Once it had attributed impacts by fire simulation to the corresponding ignition locations, PGE applied a smoothing process to convert the vector datatype to rasters, while also gap-filling the vector data. PGE first converted each set of vector ignitions for a given weather type to a 120 m raster, using an inverse distance weighting (IDW) algorithm using the four nearest ignition points, an exponential distance weighting of 1.5, and a maximum search distance of 1,500 m. The maximum search distance was intentionally large to fill in data gaps created by the original ignition lattice falling on areas of non-burnable fuel cells, accounting for fires that do not spread beyond the ignition cell.

Wildfire Threat Index (WTI)

PGE calculates the Wildfire Threat Index (WTI) as the product of conditional IPI, CI, and the weighting of the WTP, which were calculated at the original gridMET resolution and smoothed to the coincident 120 m resolution.

The resulting WTI raster and vector data provide an estimate of relative wildfire threat across the analysis area for the range of weather conditions specified. As the product of IPI and CI, WTI allows PGE to identify locations with the greatest combination of utility-related ignition and resulting wildfire damage potentials.

Conditional Wildfire Threat Index

The overall WTI integrates the results from all 216 weather types, while a conditional WTI (cWTI) for each individual weather type provides an estimate of wildfire threat for specific weather conditions. The cWTI is simply the product of the individual weather type IPI and CI.

PGE Wildfire Risk Assessment Results by HFRZ

Zone #		1	2	3	4	5	6	7	8	9	10
Asset Density	Relative Commercial and Res Meter Count	6	2	5	3	4	8	5	4	3	3
Asset density (per SqMi)		252	147	260	194	161	497	165	88	77	51
	Share of all HFRZ assets	32	3	6	214	12	3	9	4	7	12
Land area SqMi		61	10	11	34	34	3	25	22	42	111
Weather Threat/ Pyrologix Calculations	Probability of Exceeding Manual Control	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Extreme Burn Probability		.2-.4	.2-.4	.2-.4	.2-.4	.2-.4	.2-.4	.2-.4	.2-.4	.2-.4	.2-.4
	Heat Intensity per unit area - Scenario 18	10523	13221	7778	7537	7069	8798	8570	12520	12979	12774
WTI MEAN - Scenario 118		2793110	14649487	19637320	20570382	11673496	7232637	4728634	4627615	17186568	35309464
	CI MEAN - Scenario 118	315	106	582	496	305	119	162	114	263	163
IPI MEAN - Scenario 118		80	87	82	78	97	134	141	184	218	221
Accessibility / Terrain	Fire station within 5 min	4	1	3	2	1	5	1	1	1	2
Road condition vulnerability		4	0	0	1	1	0	1	1	1	3
	Slope – Mean	477	308	129	351	319	256	231	183	176	195
Aspect – Mean		260	263	324	283	298	92	199	168	104	112
Social Indicators	% households 200% below fed poverty line	25	26	18	23	16	8	17	16	22	37
Household Disability Composition		18	13	12	15	14	8	13	11	15	20
	Hispanic or Latino	7	8	2	3	3	4	5	9	5	7
Age 65+		25	17	20	18	22	16	20	13	18	16
	Housing/transportation vulnerability	30	30	20	46	35	12	56	30	32	78
Overall social vulnerability		30	35	22	37	34	5	11	16	30	65
Ecological & Cultural Vulnerability	Critical Habitats	2	3	1	2	3	1	3	2	2	2
Cultural/historical/protected areas		3	3	3	3	2	2	1	1	2	3

Wildland / Urban Interface	% in WUI	90	75	100	90	20	85	70	70	50	50
USDF WF Risk to Communities		1778	657	146	7	69	75	28	6.3	6	7
Outage History	June-Sept outages 2017-2021 on UG	101	28	41	20	9	15	13	7	16	18
June-Sept outages 2017-2021 on UG - avg duration		2960.405	575.72	430.8725	336.616	1165.777	453.5525	257.5067	184.19	1118.426	342.285
	June-Sept outages 2017-2021 on OH	246	44	77	130	105	55	90	55	203	83
June-Sept outages 2017-2021 on OH - avg duration		1940.033	921.71	292.6325	722.6057	1259.567	659.32	547.1725	317.1633	391.9871	277.6914

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December 29, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301

Re: Docket UM 2209
Idaho Power Company Wildfire Protection Plan

Attention Filing Center:

Please find attached for filing an electronic copy of Idaho Power Company's (Idaho Power or Company) 2023 Wildfire Mitigation Plan (WMP), which is submitted in compliance with Oregon Administrative Rule 860-300-0020(2).

Idaho Power's 2023 WMP reflects significant progress in the evolution of its wildfire mitigation efforts and builds on the 2022 WMP as approved by the Commission. The 2023 WMP includes a new Executive Summary and an additional appendix, both of which serve as aides in understanding and tracking Idaho Power's wildfire mitigation work. The Executive Summary provides a review of the 2022 wildfire season and the Company's actions over that time period, as well as discussion of lessons learned that will be applied to the 2023 wildfire season and beyond. The new appendix, Appendix C, provides Oregon-specific insights and maps Oregon requirements and Commission recommendations to relevant sections of the WMP. Additionally, the Company has revised and/or expanded several sections of its WMP to provide more comprehensive coverage of topics—for example, Section 10 of the WMP has been entirely rewritten to better explain the Company's communication efforts with its customers, public safety partners, and within the communities in which it serves.

The 2023 WMP also complies with the Commission's requirement to identify wildfire-related expenditures. In addition, the Company has filed an application for the deferral of its wildfire-related costs in docket UM 2270 contemporaneously with this 2023 WMP that details the jurisdictional allocation of wildfire-related costs between Oregon and Idaho.

Idaho Power appreciates Commission Staff's ongoing wildfire-related work and looks forward to Staff's review of the Company's 2023 WMP.

Very truly yours,

Alison Williams

AW:sg
Enclosures

WILDFIRE MITIGATION PLAN

Version 5 – Updated December 2022

2023

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Review/Revision History

This document has been approved and revised according to the revision history recorded below.

Review Date	Revisions
Jan. 22, 2021	WMP Version 1 was filed with the Idaho Public Utilities Commission and posted to the Idaho Power website.
Dec. 29, 2021	Modifications including expanded cost-benefit discussion, plan progress and updates, and inclusion of Idaho Power's Public Safety Power Shutoff plan.
March 18, 2022	Added Appendix C.
June 28, 2022	Added information to comply with the Public Utility Commission of Oregon's conditions of approval of Idaho Power's 2022 Wildfire Mitigation Plan.
Oct. 19, 2022	Updated cost table within the WMP and filed with the Idaho Public Utilities Commission.
Dec. 29, 2022	WMP Version 5.0, including 2022 season in review, changes for 2023 season, and addition of Appendix C—Oregon Wildfire Requirements and Recommendations.

EXECUTIVE SUMMARY

Idaho Power is dedicated to the safety of our customers and communities, and to delivering reliable, affordable energy. In pursuit of that mission, we built off our existing Wildfire Mitigation Plan (WMP) and took major steps in 2022 to enhance our situational awareness in the field, enhance vegetation management, further harden the electrical system, and expand and better the ways in which we communicate and alert customers and communities about wildfire and wildfire risk. As the company enters its third year with a WMP, this new edition (Version 5.0) has been improved to reflect key learnings, feedback from stakeholders, and a focus on new technology. The WMP also provides supporting information on wildfire requirements and actions specific to our Idaho and Oregon regulators, but the document remains—first and foremost—an evolving guide that provides holistic and prudent strategies for reducing wildfire risk.

This Executive Summary—a new introduction in the 2023 WMP—provides a comprehensive summary of the 2022 wildfire season and the company's lessons learned and progress toward our wildfire mitigation objectives. Additionally, the Executive Summary previews changes to the company's risk management framework and lessons learned that will inform 2023 wildfire mitigation efforts and beyond.

2022 Weather and Fire Potential

The spring of 2022 brought above normal precipitation and below normal temperatures. As an example, parts of southern Idaho—including the Boise area—experienced heavy snowfall in the second week of May 2022.[1] This led to an abundance of fuels across the region. The summer months saw record high temperatures and below normal relative humidity that increased wildfire potential. Idaho Power atmospheric scientists conducted regular forecasts during wildfire season to determine a daily Fire Potential Index (FPI) value across the company's service area. The FPI is used to inform Idaho Power's on-the-ground, operational strategies when the fire potential is high.

A combination of record heat and low humidity led to a dramatic increase in FPI levels throughout the summer of 2022. There were nearly three times as many high-fire-potential days as in 2021. Despite the seasonal challenges, the company fulfilled and executed the WMP as planned for 2022.

[1] Carolyn Komatsoulis. 2022. Idaho Press. It's Pretty Unusual: Half-Inch of Snow, Power Outages Make for Manic Monday in Boise. May 2, 2022.

Figure 1
A field team installs a mesh wrap on a wood pole in 2022

Idaho Power continues to monitor climate variability and changing conditions to determine how wildfire risk is shifting season to season and in the longer term. Historical data shows temperature has increased over the past 80 years in southern Idaho and eastern Oregon. Studies show a connection between higher temperatures and increased wildfire activity, both in intensity and size of wildfires.[2] Further, extreme fire weather days are increasing, and fire season is getting longer.[3]

As climate conditions change, the company is committed to monitoring increased wildfire risk and enhancing the WMP to keep customers and communities safe.

Impacts of Wildfires in 2022

This year, both Idaho and Oregon had fewer wildfires and acres burned during wildfire season than the previous 20-year average.[4] However, wildfires did affect Idaho Power equipment both

[2] Idaho reviewed academic, scientific, and governmental climate change studies, including those from the Center for Climate and Energy Solutions, the US Environmental Protection Agency, the National Aeronautics and Space Administration, the National Oceanic and Atmospheric Administration, North Carolina State University, and National Geographic.

[3] In late 2022, Idaho Power analyzed temperatures over the last 80 years in the Idaho Power service area to assess changing climate conditions. The analysis showed that daily high temperatures and extreme weather events are increasing.

[4] Interagency Fire Center. Current National Statistics. www.nifc.gov/fire-information/statistics.

inside and outside of our service area. Three major wildfires threatened or burned wood structures. In some cases, we de-energized lines to keep firefighters safe.

Table 1
Wildfires impacting Idaho Power operations and facilities in 2022

Incident Name	Location	Fire Discovery Date	Containment Date	Acres	Cause	Facilities Impacted
Moose	17 Miles North of Salmon, ID	7/17/2022	11/9/2022	130,144	Unattended Campfire	Transmission
Four Corners	6 Miles west of the City of Cascade, ID	8/13/2022	10/20/2022	13,702	Lightning	Distribution
Double Creek	10 miles SE of Imnaha, OR	8/30/2022	10/25/2022	175,937	Lightning	Transmission

Idaho Power's mapping applications include geographic information system (GIS) data for active wildfires to inform operational planning and provide insight into areas that could be threatened throughout the fire season. The company monitored fire activity throughout the season to compare fire behavior to modeling. We expect to learn more about how real-time fire analytics can inform risk-based decision-making in coming fire seasons.

Key Objectives of 2022 WMP

Idaho Power met the 2022 WMP's key objectives, including the completion of major projects to ensure the WMP could be effectively carried out. A new Public Safety Power Shutoff (PSPS) program was implemented and all processes and procedures guiding customer communication, weather forecasting, switching plans and de-energization criteria were completed before fire season. This includes the installation and commissioning of a new communication system used to expedite notifications of PSPS events via voice, text messaging, and e-mail. We also installed 17 protective devices to isolate line segments and provide a means of remote de-energization.

Figure 2
A line worker installs a spark prevention unit near Eagle, Idaho

Overview of 2022 WMP Progress

By almost all measures, Idaho Power met or exceeded its WMP goals in 2022. Work plans are established at the beginning of the year and these items are tracked throughout the year to identify areas needing corrective action or attention. As some wildfire mitigation work is on a rotating cycle based on wildfire season (and not the calendar year), some of the items listed are still in progress at the time of writing this 2023 WMP.

Idaho Power's Progress Toward 2022 Wildfire Mitigation Goals

Table 2
2022 WMP activity summary and results

Plan Area	Wildfire Mitigation Plan Activities	2022 Goal	Completed	% Complete	2023 Goal
System Hardening	**Distribution System Hardening**				
	System Hardening Line Miles	48	48.91*	102%	69
	Overhead Line Miles Converted to Underground	1.85	1.85	100%	1
	Expulsion Fuse Replacement	930	942	101%	1319
	Surge Arrester Replacement	830	839	101%	1175
Feeder Segmentation	**Segmentation Devices**				
	Installation or Relocation of Automatic Reclosing Devices	17	17	100%	8
Fire Mesh Installation	**Transmission Fire Mesh Installation**				
	Red Risk Zone Poles	492	492	100%	-
	Yellow Risk Zone Poles	406	585	144%	870
Asset Inspections	**Transmission Inspections**				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	923	923	100%	923
	Infrared Thermography Patrol (Structures)	923	923	100%	923
	Distribution Inspections				
	Wildfire Pre-Season Patrol - Red Risk Zones (Structures)	20,192	20,192	100%	20,192
	Infrared Thermography Patrol - Red Risk Zones (Structures)	3,000	3,800	127%	4,000
Vegetation Management	**Pruning Cycle**				
	Transition to a 3-Year Pruning Cycle (circuits)	282	173	70%**	320
	Enhanced Vegetation Management				
	Annual Patrol - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Annual Mitigation - Red & Yellow Risk Zones (circuits)	65	65	100%	65
	Mid-Cycle Patrols - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Mid-Cycle Pruning - Red & Yellow Risk Zones (circuits)	47	47	100%	1
	Hazard Trees Identified and Pruned	-	77	100%	100% of All Identified
	Hazard Trees Identified and Removed	-	49	100%	100% of All Identified
	Audits of Pruning Activities - Red & Yellow Risk Zones (worksites)	6,324	977	15%**	100% of All Identified
Meteorology	**Idaho Power Weather Stations**				
	Weather Station Installations	5	5	100%	5

*Excludes hardening work outside of wildfire risk zones
**Estimated year end completion

As can be observed from the numbers above, vegetation management is a challenging area. Much of the delay in reaching 2022 goals is attributable to broader challenges in the workforce. Idaho Power uses contractors to perform vegetation management and audit work. The company witnessed labor shortages, more inexperienced contract workers than in the past, and increased turnover that led to lower vegetation management production levels throughout the year. Vegetation management production was also lower than anticipated because more climbing work was required than originally expected. Climbing to prune or remove vegetation requires contractors with more skill and takes more time. Despite these challenges, Idaho Power continues to work with contractors to push toward its goals and estimates that, by the end of the calendar year, the production level will be near 70% of target.

Audits were also impacted by resource availability, as contractors did not reach full staff levels until December 2022. Because of this, random sampling was used in lieu of auditing all vegetation management work in wildfire risk zones. Idaho Power will work with contractors at the end of 2022 to develop corrective action plans and make necessary adjustments to meet targeted performance levels in 2023.

Regarding customer communication in 2022, Idaho Power used several methods to inform customers throughout the year of our WMP and PSPS plan. These included social media, radio, customer newsletters, postcards, and voice and text messaging. Before the 2022 wildfire season, the company focused on asking customers—especially those in PSPS potential zones—to update their contact information and prepare for potential PSPS events. Additionally, the company conducted over 20 in-person and virtual meetings to engage with customers, counties, and fire and other public agencies to discuss and seek feedback on the WMP and PSPS efforts.

Figure 3
Idaho Power developed an educational video to explain PSPS

Fortunately, the company did not need to fully implement a PSPS in 2022. However, the company's planning and communication apparatuses were tested in one instance in Pocatello, Idaho, where the company anticipated a PSPS event due to high winds and extremely high fire potential. The company took the steps to inform public safety partners, critical facilities, and customers in the area that a PSPS was imminent. Rain showers preceded high winds in the area and the PSPS event was canceled before de-energization took place.

Looking Ahead—Expanded Mitigation Activities

As detailed in the WMP, Idaho Power deploys a comprehensive and multi-faceted strategy to reduce wildfire risk. The company plans to implement new activities and expand existing ones in 2023. The list below summarizes new or expanded activities.

Infrastructure Hardening
In 2022, we hardened approximately 49 line miles to decrease the risk of wildfire in Red Risk Zones—areas with the highest wildfire risk based on wildfire probability and potential impacts. The hardening program is 26% complete, with Red Risk Zones given the highest priority at this time. This work will increase in 2023 by 40% and include hardening to 69 line miles.

Strategic Undergrounding
In 2022, Idaho Power buried approximately 1.85 miles of overhead distribution line in areas of highest wildfire risk. This work primarily targeted the main trunk of distribution feeders. In 2023, we will target a smaller line segment in an area that includes residences.

The company's goal is to work through the complexities and costs associated with burying primary overhead powerlines, overhead services, and converting customer-owned service-entrance equipment. This work will take place in a PSPS zone in Idaho with high fire probability and potential impact. The projects in 2022 and upcoming work in 2023 will inform future underground conversion strategies by helping us weigh costs and risk-reduction benefits against those of traditional feeder hardening and covered conductor conversions.

Vegetation Management

Idaho Power's effort to achieve a three-year pruning cycle will continue in 2023. It is a critical aspect of meeting our objective to reduce wildfire risk. We will expand brush clearing and applying ground sterilant around wood poles to reduce fuels. We are also exploring an opportunity to partner with the National Forest Foundation, Boise National Forest, Bureau of Land Management, and local fire districts on a shared stewardship program in the Boise Front. This work is expected to provide a means for Idaho Power to participate in fuel reduction activities outside of the right of way, which will reduce wildfire risk by decreasing surface fuels and the potential of tree contact.

Figure 4
A contractor trims trees in a bucket truck

Risk Modeling

Risk modeling of Idaho Power's service area is used to prioritize mitigation activities. In 2023, we will re-evaluate our risk modeling by incorporating new structure information based on 2020 Census data and explore new areas of consequence based on the feedback received in the past year from fire agencies and customers.

Situational Awareness
The FPI is forecasted daily during fire season and provides critical information that informs operational changes during days with high fire potential. In 2023, we will work to improve the communication and calculation of the FPI by creating more clear and concise messaging to stakeholders.

PSPS
While the company did not proactively de-energize any customers as part of its PSPS program in 2022, engagement with communities and customers this year highlighted their concerns—specifically the inability to communicate or suppress fire via electric wells and water pumps without power. This feedback highlights the need for the company to find ways to limit the impact and frequency of future PSPS events. Many of the activities being pursued here, such as strategic undergrounding and utilizing covered conductor, will decrease the likelihood of PSPS. However, PSPS will remain a tool available to the company to mitigate wildfire risk during extreme fire weather conditions.

Figure 5
Idaho Power uses visual graphics to illustrate the conditions that could require a PSPS event

Segmentation
We completed the installation of 17 automatic reclosing devices (reclosers) in Red Risk Zones as part of an effort to isolate circuit segments and improve reliability for customers outside of those zones. In 2023, we will continue this work and install an additional eight reclosers in Red Risk Zones.

New Technology and Innovations
New technology and innovative programs were explored in 2022 to find new ways to reduce the risk and impacts of wildfire. In 2023, we will conduct pilots based on our findings with the goal of learning more about their implementation complexities and to analyze costs and risk reduction benefits prior to fully integrating into the WMP. These pilots or trials include the following:

- Satellite Imagery—Using satellite imagery to detect vegetation encroachment and hazard trees.

- Covered Conductor—Covered conductor is a solution used throughout the industry to decrease the potential of ignition if an object contacts powerlines. A trial of covered conductor will be carried out in our training yard to determine overall costs, tooling requirements, work methods, and construction standards and specifications.

- Structural Resilience of Wood Poles—We will increase situational awareness in Red Risk Zones by performing a survey of distribution poles using Light Detection and Ranging (LiDAR) technology to identify structural loading capacity of existing wood poles.

- Shared Stewardship—We will partner with federal agencies on a shared stewardship fuel reduction program in forested areas and evaluate the benefits in terms of reduced surface fuels and fire spread potential. The collaboration will also provide the company with the opportunity to work with land managers and owners to expand vegetation management and reduce the potential of ignition from vegetation contact.

- Fire Detection Cameras—In 2022, we explored the benefits that cameras can have in early fire detection and became part of the Wildfire Detection Camera Strategy Work Group in Oregon. We are working to identify optimal locations and developing partnerships with state and federal agencies and will expand our knowledge of cameras that utilize artificial intelligence for fire detection. We plan on piloting cameras in 2023 to further understand the complexities of installations, permitting, systems used for notification, and overall accuracy. The pilot will be critical in determining a long-term strategy for the use of cameras to reduce wildfire risk.

Lessons Learned

Idaho Power has conducted its own assessment of lessons from the 2022 wildfire season and the company's wildfire mitigation practices. The following lessons learned were developed by supplementing this analysis with feedback heard from stakeholders, customers, public safety partners, peer utilities, and through wildfire-related forums, research, and education.

Pre-Wildfire Season Patrols

Idaho Power strives to complete wildfire patrols prior to the start of each wildfire season to identify issues that may pose a risk of ignition if left unchecked. Above-normal precipitation and below-normal temperatures in the spring months of 2022 created access issues in mountain areas where snow levels were several feet deep. Late, heavy snow delayed completion of these patrols until mid-June, which, while later than target, was still prior to the onset of conditions conducive for wildfire.

Situational Awareness

The FPI is an essential tool to support operational decision making. It includes detailed forecasts of 148 different geographical areas or zones throughout the service area and is used to determine when a PSPS is necessary. The preparation for a PSPS event in August 2022 highlighted an opportunity to improve the communication and precision of the forecasts. In that case, a line segment subject to the potential PSPS was included in two different FPI zones that had different fire potential across their geographical areas. Initially, this created confusion as to which forecast to use for decision-making purposes. In 2023, we will review areas that have overlapped FPI zones and refine mapping and forecasted boundaries to eliminate the potential of this situation occurring again.

Vegetation Management
Pruning levels in 2022 did not meet the target established for the year largely due to labor issues. We added outsourced crews from throughout the country to assist in conducting vegetation management activities and expect to reach approximately 70% of targeted vegetation management pruning by the end of 2022. In 2023, we will conduct a thorough review of all activities and assess means of working with contractors to drive towards 2023 production goals.

Expansion of the Wildland Urban Interface
As the population in Idaho Power's service area continues to grow, we've seen an expansion of new construction in the wildland urban interface (WUI). This expansion creates challenges for wildfire mitigation as new wildfire risks emerge. In 2023, we will analyze the growth of the WUI and create new strategies to address new risks.

Functional Exercises
Two functional exercises were conducted in the spring of 2022 to test processes and procedures needed to fully execute the PSPS program. The exercises were beneficial and ensured that the company was prepared to effectively carry out a PSPS prior to the onset of severe fire weather. Forty action items were identified throughout the exercises and consisted of refining and improving communication methods, timing, documentation, and website functionality. We found that PSPS events can be complex and occur within different parts of the company's service area simultaneously. To help ensure expedited and accurate communication for all potential scenarios, templates were developed for communication activities involving customers, Public Safety Partners, Emergency Support Function (ESF-12), and departments within the company. The templates will be reviewed and improved as needed in 2023.

List of Stakeholders
The PSPS functional exercises highlighted the need for accurate and readily available lists of Public Safety Partners and critical facilities. We developed a central repository for all information related to PSPS which includes contacts for Public Safety Partners, operators of critical facilities, and Emergency Support Function ESF-12 personnel.

Estimated Time of Restoration
As with all outages, having accurate estimates for the time or restoration (ETR) is a priority. The PSPS functional exercises highlighted that setting an initial ETR for PSPS events is more challenging than ordinary unplanned or planned outages. The company determined that the ETR for a PSPS should take into consideration the duration of the weather event and the time needed for safety patrols to occur. Internal atmospheric scientists became a crucial part of determining the duration of weather events. Operational plans were developed for each region to guide restoration and switching procedures to expeditiously restore power during a PSPS. These plans include estimated patrol times which are also used for establishing an initial ETR. We plan on reviewing any assumptions in the operational plans each year and

include lessons learned from the previous year into the patrol estimates to ensure we are providing the best information possible.

Field Observer Program
PSPS events are carefully evaluated by an assessment team to balance wildfire risk with potential PSPS impacts on the customers and the communities we serve. In 2022, we expanded the PSPS decision-making process to include real-time on-site conditions from Field Observers (FOBs). FOBs are Idaho Power personnel positioned within pre-defined PSPS zones to monitor system conditions and periodically report observations to help inform the PSPS assessment team. The location of FOBs in PSPS zones was examined to ensure their safety during severe weather conditions and communication templates were developed to ensure accurate and consistent fire weather reporting. We found that, in some areas, cellular and radio communication does not exist and we had to rely on satellite messaging services. The FOB program became more complex than anticipated, and we will work in 2023 to improve the documentation and procedures as well as increase the number of qualified resources to perform FOB duties in situations where multiple areas are at risk of PSPS.

Customer Communication
Notifying customers in PSPS zones was a priority this year and consisted of telephone, text, and e-mail outreach. We found that some of the targeted customers did not have up-to-date contact information associated with their account. Several efforts were made to encourage customers to update their contact information, and additional information was mailed to those customers without current contact information. This will be a continued focus in 2023.

Community Feedback
The company conducted over 20 WMP and PSPS plan presentations throughout the service area, to advise customers of our plans and to solicit feedback to help inform future versions of the WMP. Seven public meetings were held in Oregon at the end of fire season, and we received good feedback from local fire chiefs, emergency managers, and the general public. Feedback and themes from these meetings and others throughout the year will be incorporated into the 2023 WMP and include:

- Adjusting the timing of public meetings in Oregon to coincide with fire season
- Partnering with agencies and other programs, such as Firewise, when conducting public meetings
- Reviewing risk modeling to include additional areas of consequence
- Having more collaboration with fire agencies including the Idaho Bureau of Land Management (BLM), Forest Service, Baker County, and La Grande Rural Fire Protection District

Vulnerable Populations

Idaho Power participated in two mock events, one conducted by Malheur County in Oregon and another as part of the Idaho Office of Emergency Management's Cascade Rising event. These two events highlighted two opportunities to improve our support for vulnerable populations during an outage or PSPS event. First, the Red Cross was added as a Public Safety Partner in Malheur County based on their role in coordinating Community Resource Centers (CRC). Second, the emPower program was identified as a tool to help notify customers on durable medical devices (DME) if a PSPS event is predicted. Targeted outreach to vulnerable populations was also conducted to include outage preparedness flyers sent to Meals on Wheels participants. In 2023, Idaho Power will further the efforts made in identifying and communicating with vulnerable populations.

Risk Management Process

A review of Idaho Power's risk management process used in developing previous versions of the WMP was completed in 2022. The review found opportunities to improve by strategically incorporating a more formalized risk management process into the WMP. The International Standardization Organization (ISO 31000-2018) is a recognized standard for risk management and will be integrated into the 2023 plan. The standard will help position the company to achieve the objectives of the WMP by fostering continuous improvement and ensuring a consistent approach to risk-based decision making.

REGULATORY CONTEXT

As part of Idaho Power Company's (Idaho Power or company) commitment to deliver safe, reliable, and affordable energy, the company developed a comprehensive Wildfire Mitigation Plan (WMP) to reduce wildfire risk associated with its facilities. The WMP has three core objectives:

1. Reducing wildfire risk for the safety of Idaho Power's customers and the communities in which it operates.

2. Ensuring the continued and reliable delivery of electricity to more than 600,000 retail customers in Southern Idaho and Eastern Oregon.

3. Furthering the company's good stewardship of the beautiful and natural lands within Idaho Power's service area and beyond.

Idaho Power released its inaugural WMP in January 2021. The company's WMP is a living document that will evolve over time. Idaho Power will seek to review, modify, and expand the WMP in the coming years to reflect shifts in industry best practices and to ensure the company is following procedures and requirements established by its regulators. Given that Idaho Power operates in both Oregon and Idaho, below is a description of recent wildfire-related regulatory activities by state.

Idaho

On January 22, 2021, Idaho Power proactively filed its first WMP with the Idaho Public Utilities Commission (IPUC). The company's application provided a narrative of Idaho Power's effort to develop the WMP, including discussion of risk analysis across its service area and evaluation of specific wildfire mitigation activities (e.g., enhanced vegetation management and system hardening) the company would undertake in the coming fire season. Idaho Power asked the IPUC for authority to defer the Idaho jurisdictional share of incremental operations and maintenance expenses and capital depreciation expenses related to implementing the measures in the WMP, as well as incremental insurance costs.

On June 17, 2021, the IPUC issued Order No. 35077, granting the company's application and allowing cost deferral of all incremental wildfire mitigation and insurance expenses identified in Idaho Power's application.

On October 20, 2022, the company filed an updated WMP and a new application for deferral of newly identified wildfire mitigation-related costs.

Oregon

In August 2020, the Public Utility Commission of Oregon (OPUC) opened an informal rulemaking related to mitigating wildfire risks to utilities, utility customers, and the public. The scope of this docket (AR 638) shifted following the 2020 wildfire season, splitting into two tracks—a temporary wildfire rulemaking to govern the 2021 wildfire season and a secondary track to establish replacement permanent rules for the 2022 fire season.

On July 19, 2021, Oregon Governor Kate Brown signed into law Senate Bill 762 (SB 762), a wildfire bill that, among other actions, established minimum requirements for utility wildfire protection (or mitigation) plans. The bill required that utilities file inaugural plans no later than December 31, 2021.

In response to the passage of SB 762, the OPUC halted the permanent wildfire rulemaking in AR 638 and opened docket AR 648 to develop interim permanent rules adhering to the requirements and timing of the new law. On September 8, 2022, the OPUC issued Order No. 22-335 in AR 638 finalizing requirements specific to requirements for utility WMPs.

Idaho Power added Appendix C to the WMP to provide Oregon-specific information related to wildfire requirements and recommendations.

1. Introduction

1.1. Background

In recent years, the Western United States has experienced an increase in the frequency and intensity of wildland fires (wildfires). A variety of factors have contributed in varying degrees to this trend including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors.

While Idaho Power has not experienced catastrophic wildfires within its service area at the same level experienced in other western states, such as California and more recently certain areasin Oregon, millions of acres of rangeland and southern Idaho forests have burned in the last 30 years.[5] In that same time period, the wildfire season in Idaho has expanded by 70 days.[6] Idaho's wildfire season is defined by Idaho Code § 38-115 as extending from May 10 through October 20 each year, or as otherwise extended by the Director of the Idaho Bureau of Land Management (BLM). Oregon's wildfire season is designated by the State Forester each year pursuant to Oregon Revised Statute § 477.505 and typically begins in June. Idaho Power's operational practices account for the differences between Idaho and Oregon's wildfire seasons and requirements.

1.2. Idaho Power Profile and Service Area

Idaho Power is an investor-owned utility headquartered in Boise, Idaho, engaged in the generation, transmission, and distribution of electricity. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power serves approximately 600,000 retail customers throughout a 24,000 square mile area in southern Idaho and eastern Oregon (see Figure 6).

[5] Rocky Barker, *70% of S. Idaho's Forests Burned in the Last 30 Years. Think That Will Change? Think Again.*, Idaho Statesman, October 4, 2020.

[6] Ibid.

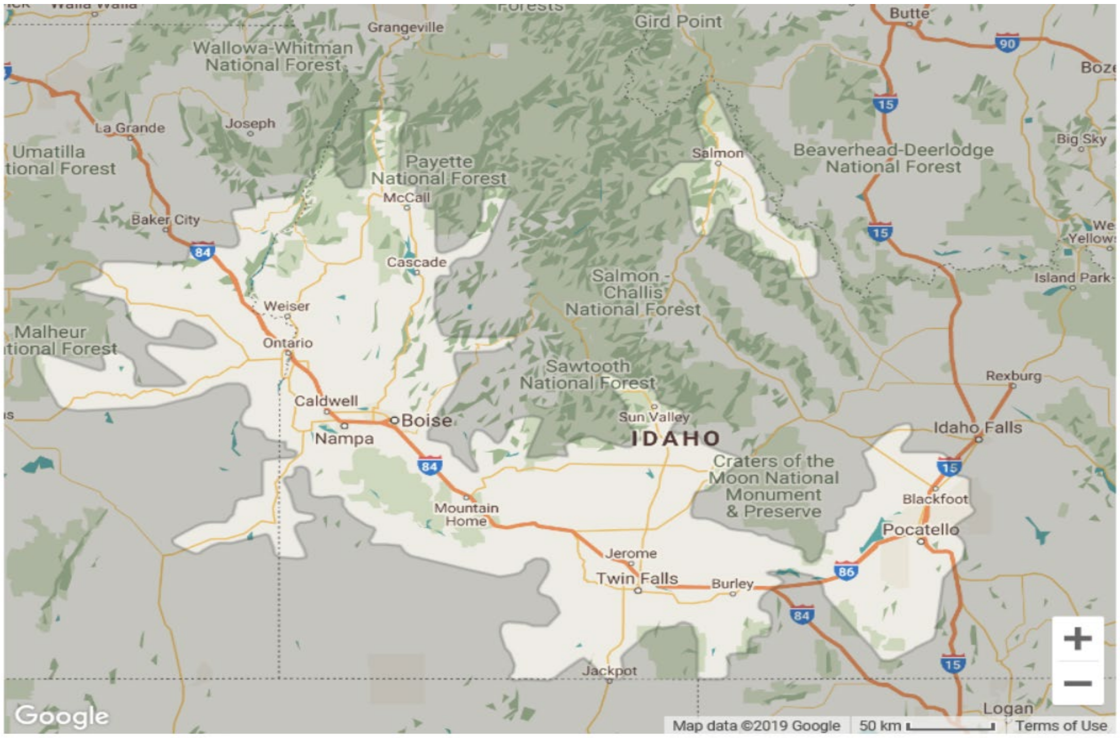

Figure 6
Idaho Power service area

Of Idaho Power's 24,000 square mile service area, approximately 4,745 square miles are located in Oregon and 19,255 in Idaho. Approximately 20,000 customers are served in Oregon and 580,000 in Idaho.

1.3. Asset Overview

Idaho Power delivers electricity to its customers via more than 310 substations, 4,800 miles of overhead transmission lines, and 19,300 miles of overhead distribution lines. Table 3 summarizes the overhead powerline asset information by state. Approximately 2,871 pole miles (12%) are in Oregon and 21,042 (87%) are in Idaho.

Table 3
Overhead transmission voltage level and approximate line mileage by state (Dec. 31, 2021)

ASSET	TOTAL	IDAHO		OREGON		MONTANA		NEVADA		WYOMING	
	Pole Miles	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%
46 kV Transmission Lines	383	383	100								
69 kV Transmission Lines	1,136	743	65	344	30	50	4				
115 kV Transmission Lines	3			3	100						
138 kV Transmission Lines	1,448	1,242	86	141	10			65	4		
161 kV Transmission Lines	84	84	100								
230 kV Transmission Lines	1,148	927	81	219	19						
345 kV Transmission Lines	473	364	77							110	23
500 kV Transmission Lines	103	53	51	50	49						
Total OH Transmission Lines	4,778	3,796	80	757	16	50	1	65	1	110	2
Total OH Distribution	19,297	17,183	89	2,114	11						
Total OH Pole Miles	**24,075**	**20,979**	**87**	**2,871**	**12**	**50**	**0.21**	**65**	**0.27**	**110**	**0.46**

1.4. Objectives of this Wildfire Mitigation Plan

The primary objectives of this WMP are to identify and implement strategies to accomplish the following:

1. Reduce wildfire risk associated with Idaho Power's transmission and distribution (T&D) facilities and associated field operations.

2. Improve the resiliency of Idaho Power's T&D system in a wildfire event, independent of the ignition source.

3. Comply with all wildfire mitigation requirements established by its regulators.[7]

Idaho Power's approach to achieving these objectives includes the following actions:

- Engage with government and industry entities and electric utility peers to ensure understanding and commonality of wildfire mitigation plans.

- Utilize a risk-based approach to quantify wildland fire risk that considers *wildfire probability* and *consequence* to identify areas of elevated wildfire risk within Idaho Power's service area. These identified areas are then incorporated in Idaho Power's geographic information system (GIS) mapping.

- Create specific and targeted operations and maintenance practices, system hardening programs, vegetation management, and field personnel practices to mitigate wildfire risk.

[7] The OPUC established docket AR 648, the interim permanent wildfire rulemaking, after the Oregon legislature passed Senate Bill 762. The bill created a requirement for public utilities in Oregon to submit "wildfire protection plans" to the OPUC by December 31, 2021.

- Incorporate information regarding current and forecasted weather and field conditions into operational practices to increase situational awareness.
- Employ public safety power shutoff (PSPS) protocols for Idaho Power's service area and transmission corridors.
- Evaluate the performance and effectiveness of strategies identified in this WMP through metrics and monitoring. The WMP and all its components will be reviewed prior to wildfire season each year.

2. Government, Industry, and Peer Utility Engagement

2.1. Objective

Idaho Power recognizes the importance of engaging with federal, Idaho and Oregon State governments, and local governments as an integral part of mitigating wildfire risk. Idaho Power also recognizes the importance of engagement and outreach with respect to potential future PSPS events to minimize customer impact.

Idaho Power's wildfire mitigation plan and outage preparedness strategy includes specific activities to engage with key stakeholders to share information, gain feedback, and incorporate lessons learned. Peer utility engagement is crucial to ensure the company's efforts are informed by the best practices of its peers in Idaho and Oregon.

2.2. Government Engagement

Much of Idaho Power's service area extends over land managed by the BLM and U.S. Forest Service. Idaho Power engages with both agencies to share information and identify areas and activities that are mutually beneficial. For example, Idaho Power allowed for an extended firebreak along Highway 93 in Jerome County, Idaho, on its property to help with BLM wildfire mitigation initiatives.

Idaho Power is also a member of the Idaho Fire Board, which was initiated by the U.S. Forest Service. Membership is voluntary and currently includes the Forest Service, BLM, Federal Emergency Management Agency (FEMA), Idaho State Lands Department, Idaho Department of Insurance, Idaho Military Division, City of Lewiston, Idaho Power, and The Nature Conservancy in Idaho.

Idaho Power is actively engaged with both the IPUC and the OPUC with respect to wildfire mitigation activities. Idaho Power filed its WMP with the IPUC in 2021 and again in 2022. In Oregon, the company is required to submit an updated WMP by the end of each calendar year. Idaho Power continues to participate in the OPUC's Oregon Wildfire and Electric Collaborative (OWEC) and ongoing rulemaking efforts.

2.3. Industry and Peer Utility Engagement

Although Idaho Power relied on plans developed by several California utilities in drafting its own WMP, modifications were made to account for Idaho Power's considerably different risk profile. Additionally, Idaho Power participated in multiple workshops with San Diego Gas and Electric, Southern California Edison, Pacific Gas and Electric, Sacramento Municipal Utility District, and PacifiCorp. The company continues to engage with these utilities to learn about California's evolving practices.

In the Pacific Northwest, many utilities work collaboratively to understand and ensure commonality of their various wildfire mitigation plans, while accounting for the variation in each utility's unique service area. These utilities include Idaho Power, Avista Utilities, Portland General Electric, Rocky Mountain Power, Pacific Power, Chelan County Public Utility District, Puget Sound Energy, NV Energy, Bonneville Power Administration (BPA), and Northwestern Energy.

Idaho Power is also a member of both the Edison Electric Institute (EEI) and the Western Electric Institute (WEI). The company participated in multiple workshops and conferences with both entities and member utilities to evaluate the strength and effectiveness of Idaho Power's WMP in comparison to other members' plans. Additionally, Idaho Power's CEO and President is an active member of the EEI Electricity Subsector Coordinating Council Wildfire Working Group. This working group has been partnering with the U.S. Department of Energy and other government agencies to collectively minimize wildfire threats and potential impacts.

These workshops continue to prove valuable for sharing wildfire mitigation best practices and discussing new and existing technology related to wildfire mitigation. For example, EEI and WEI workshops, as well as independent investigations, led Idaho Power to expand its use of Unmanned Aircraft Systems ([UAS] also known as drones) during line patrols, replace expulsion fuses with energy limiting fuses, and add mesh wraps to wood poles in wildfire risk zones. Idaho Power has also enlisted a team of employees to focus on wildfire mitigation technologies by identifying opportunities to incorporate new and innovative technologies into Idaho Power's wildfire mitigation efforts.

2022 Industry and Peer Utility Engagement

Idaho Power continues to engage with industry groups and peer utilities to gain knowledge of new mitigation activities, industry best practices, and employing technology to reduce wildfire risk. The following summarizes 2022 activities:

- Technology—Held meetings with over 30 vendors and manufacturers to identify new technology and innovations used to mitigate wildfire risk. The findings were used to develop a roadmap and led to the creation of pilot projects in 2022 and 2023.
- Electric Power Research Institute (EPRI)—Engaged with EPRI to learn more about new technology and the attributes of covered conductor, particularly the UV performance and reliability performance.
- Utility Wildfire Symposium—Attended a symposium hosted by EPRI and Portland General Electric focused on new technology, trends, and ways to mature risk modeling.
- NW Wildfire Group—Attended biennial meetings and shared details of Idaho Power's WMP and PSPS plan with attendees including how new technology and innovative materials are being incorporated.
- WEI—Provided a presentation and details of Idaho Power's documented processes and procedures used in PSPS execution and customer notifications.
- WEI Wildfire Planning and Mitigation Virtual Meeting—Attended a two-day conference to gain insight into mitigation activities and strategies other utilities are pursuing.
- International Wildfire Risk Mitigation Consortium—Held meetings throughout the year with program managers and participated in a risk reduction seminar focused on vegetation management.
- Oregon Wildfire Detection Camera Strategy Group—Became a member of a workgroup focused on the interoperability of different camera platforms to improve fire detection, suppression efficiency, and response time. This group has provided valuable information into the benefits that cameras hold for early fire detection and how partnerships can be utilized to expedite the installation.
- Wildfire Technology Webinar—Attended webinar focused on using artificial intelligence (AI) drones for grid inspections, aerial sensors, and cameras to gain situational awareness.
- National Forest Foundation (NFF)—Attended multiple meetings with the NFF and other agencies to learn more about the benefits of fuel treatments and shared stewardship programs and how utilities have participated in other locations. Lessons learned include details of the success achieved in the Upper Arkansas Forest Fund in the State of Colorado.
- British Standards Institute (BSI) —Attended a two-day course taught by BSI to gain knowledge of the International Organization for Standardization (ISO) 31000 risk management framework and how it can be applied to the company's WMP.

3. Quantifying Wildland Fire Risk

3.1. Objective

Idaho Power's approach to quantifying wildland fire risk is to identify geographic areas of elevated wildfire risk if a wildfire ignites near a power line. Mitigation actions and programs are prioritized in those areas identified as elevated wildfire risk areas.

3.2. Identifying Areas of Elevated Wildfire Risk

Idaho Power hired an external consultant that specializes in assessing and quantifying the threat of wildfire through a risk-based methodology that leverages weather modeling, wildfire spread modeling, and Monte Carlo simulation. This methodology is not unique to Idaho Power's WMP. The California Public Utilities Commission (CPUC) used the same modeling approach (and in fact, the same consultant) in developing its CPUC Fire Threat Map. In addition, other utilities in Oregon, Idaho, Nevada, and Utah have utilized similar modeling to identify and quantify wildfire risk.

This methodology is consistent with conventional definitions of *risk*, which is usually taken as an event's *probability* multiplied by its potential negative *consequences* or impacts should that event occur. For Idaho Power's wildfire risk assessment, this formula is:

Wildfire Risk = Fire Probability x Consequence

The definition of each component is as follows:

Fire Probability. Fire volume (i.e., spatial integral of fire area and flame length) is used as Fire Probability because rapidly spreading fires are more likely to escape initial containment efforts and become extended fires than slowly developing fires. Data inputs used in the fire spread model to determine the fire volume (Fire Probability) include:

- Historical weather (temperature, wind speed/direction, relative humidity)
- Topography
- Fuel types present
- Fuel moisture content (both dead and live fuels)

Consequence. Number of structures (i.e., homes, businesses, other man-made structures) that may be impacted by a wildfire.

Wildfire Risk. Fire Probability multiplied by the Consequence. The highest Wildfire Risk areas are those where both the Fire Probability and Consequence are elevated. Conversely, combinations of low Fire Probability and elevated Consequence, or elevated Fire Probability and low Consequence typically indicate lower Wildfire Risk.

3.2.1. Wildfire Risk Modeling Process

The wildfire risk modeling process incorporated the following major steps:

1. A 20-year (2000–2019) fire weather climatology was developed utilizing the Weather Research and Forecasting (WRF) model to recreate historical days of fire weather significance across Idaho Power's service area. This analysis generated high-resolution hourly gridded fields of relative humidity, temperature, dead fuel moisture, and wind speed/direction that was used as input to a Monte Carlo-based fire modeling analysis.

2. Estimates of seasonal variation in live fuel moisture across Idaho Power's service area were developed. This was accomplished by analyzing historical fuel measurements and/or weather station observations. This step was necessary because live fuel moisture data is needed for fire spread modeling, but the WRF weather model does not provide live fuel moistures.

3. The federal LANDFIRE program was utilized to provide high-resolution (approximately 100 feet) fuel rasters for use in fire spread modeling.[8]

4. The data developed above (WRF climatology, live fuel moisture, and LANDFIRE data) was used to drive a Monte Carlo[9] fire spread modeling analysis. This Monte Carlo simulation was accomplished by randomly selecting an ignition location and a randomly selected day from the fire weather climatology developed in step 1 above. Ignition locations were limited in the model to be within a two-kilometer buffer surrounding Idaho Power's overhead T&D lines (i.e., 1 kilometer on either side). The model used equal ignition probability for all overhead distribution and transmission asset types. Urbanized areas having underground circuitry were not included in the model due to a low probability of wildfire associated with underground electrical equipment. Note that transmission lines jointly owned by Idaho Power and PacifiCorp were included in the analysis. Furthermore, the proposed Boardman to Hemingway (B2H) 500 kilovolt (kV) line route was also included in this analysis. For each combination of ignition location and time of ignition, fire progression was then modeled for 6 hours. For each modeled fire, potential fire impacts to structures were quantified using structure data. This was repeated across Idaho Power's service area for millions of combinations of ignition location and time of ignition.

5. The Monte Carlo results were processed, and GIS based data depicting fine grained wildfire risk was developed. This risk was then visually depicted on GIS based wildfire risk maps.

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[8] Chris Lautenberger, Mapping areas at elevated risk of large-scale structure loss using Monte Carlo simulation and wildland fire modeling. IAFSS 12th Symposium 2017.

[9] Ibid.

2023 Risk Modeling Update

With the help of our consultant in 2023, Idaho Power will strive to improve risk modeling to better understand wildfire risk and estimations of wildfire consequences along electric lines and equipment. Ares of focus include:

- Incorporate structure density information using 2020 Census data
- Incorporate proposed building developments in or near wildfire risk zones
- Explore new available data to potentially incorporate into wildfire probability and consequence. Examples include:
    - Fire history
    - Land use changes

Additionally, Idaho Power's risk modeling update will include assessing feedback from customers and agencies received throughout the year. Enhancements made will provide more understanding and improved methods to better inform operational decision-making and risk treatments.

Idaho Power's broader risk framework is discussed in Section 4.

3.2.2. Wildfire Risk Areas

Based on the previously described modeling, draft risk tiers were generated algorithmically[10] by an automated process. Tiers were established which, if exceeded, would classify an area as Tier 2 (elevated risk) or Tier 3 (high risk). To aid in customer and public understanding, Idaho Power also color-coded the tiers to reflect relative risk—Yellow Risk Zones (YRZ) for Tier 2 and Red Risk Zones (RRZ) for Tier 3. This was accomplished by manually setting threshold values at naturally occurring breaks. Idaho Power held several public workshops wherein tiers were reviewed and adjusted based upon consideration of local and institutional knowledge and potential impacts to communities. This was a similar approach taken by the California Public Utilities Commission in developing a state wildfire risk map. Consequently, the resulting risk tiers reflect risk relative to Idaho Power's service area only and not absolute risk. As set forth later in this plan, Idaho Power's risk profile is significantly lower than utilities serving California.

An integral part of the consultant's mapping process involved reviewing the tiers and making necessary adjustments to account for unique aspects of certain areas, including factors that may increase or decrease risk, which would not be accounted for in the computer modeling. Several factors were considered, including the following:

[10] Ibid.

- Topography and resistance to fire control
- Means of ingress and egress
- Presence/absence of defensible space
- Vulnerable populations
- Cell phone coverage
- Non-burnable land cover such as built-up urban areas

This review helped define overall tier boundaries and, in some cases, expanded Tier 3 areas or moved certain Tier 2 areas into Tier 3. For example, the Charlotte fire was a human-caused fire that occurred in Pocatello in 2012 and burned more than 1,000 acres and destroyed 66 homes and 29 outbuildings. It was a difficult fire to control and highlighted the dangers of juniper trees intermixed within the wildland urban interface (WUI). Local knowledge of this event was used to expand outlying Tier 2 areas in the vicinity of the Charlotte fire into Tier 3. As part of integrating the ISO 31000 risk management processes into the WMP, Idaho Power plans to review tier levels and boundaries as part of continuous improvement and maturing our risk modeling methods.

Table 4 provides a breakdown of pole miles in risk zones on a system-wide basis and by state. Across Idaho Power's service area, 8% of pole miles exist in elevated risk zones (either RRZs or YRZs). In Idaho, 5% of pole miles exist in YRZs and 3% exist in RRZs. In Oregon, less than 1% of pole miles exist in YRZs. The company has no RRZs in Oregon.

Table 4
Idaho Power's transmission and distribution lines by risk zone in Idaho and Oregon*

Asset	Total	Total Pole Miles within Wildfire		Wildfire Risk Zone by State											
				Tier 2 - Idaho		Tier 3 - Idaho		Tier 2 - Oregon		Tier 3 - Oregon		Tier 2 - Nevada		Tier 3 - Nevada	
	Pole Miles	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%	Pole Miles	%
Transmission Lines	4,778	517	11%	376	8%	110	2%	20	0.42%	0	0%	11	0.23%	0	0%
Distribution Lines	19,297	1,447	7%	837	4%	581	3%	29	0.15%	0	0%	0	0%	0	0%
Total Pole Miles	24,075	1,964	8%	1,213	5%	691	3%	49	0.20%	0	0%	11	0.05%	0	0%

*Geospatial analysis was performed in 2022 to reconfirm the pole miles in wildfire risk zones.

The final two-tier risk map reflecting relative increased risk in YRZs and RRZ is shown in Figure 7. The map is the foundation of Idaho Power's wildfire mitigation and risk reduction strategies. It is used to determine and prioritize targeted investments, inspection activities, and increase situational awareness for field personnel.

The risk zone map can be viewed in detail on Idaho Power's website. Individual addresses can be entered on the map to determine proximity to identified risk zones.

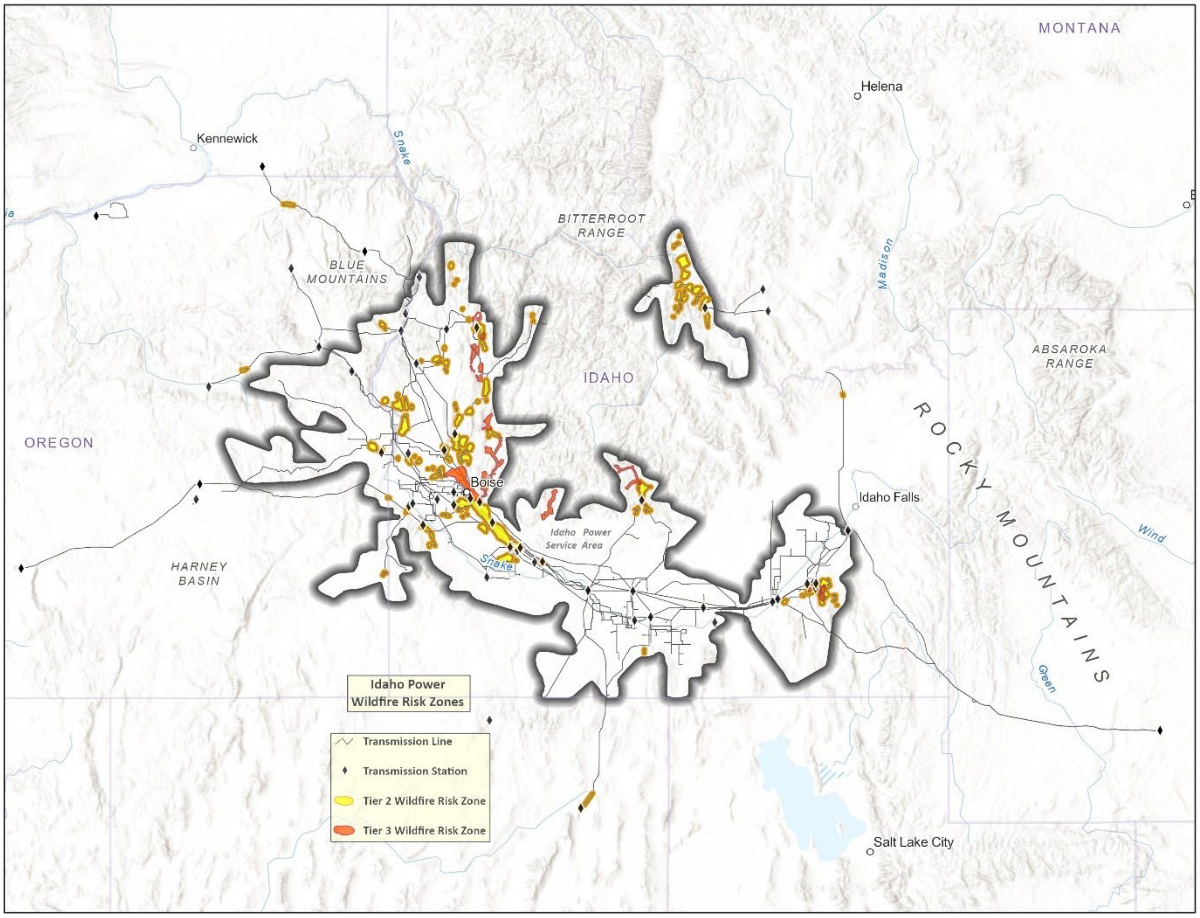


Figure 7
Wildfire Mitigation Plan—Risk Map

Additionally, Figures 8 through 11 delineate risk zones in Idaho and Oregon.

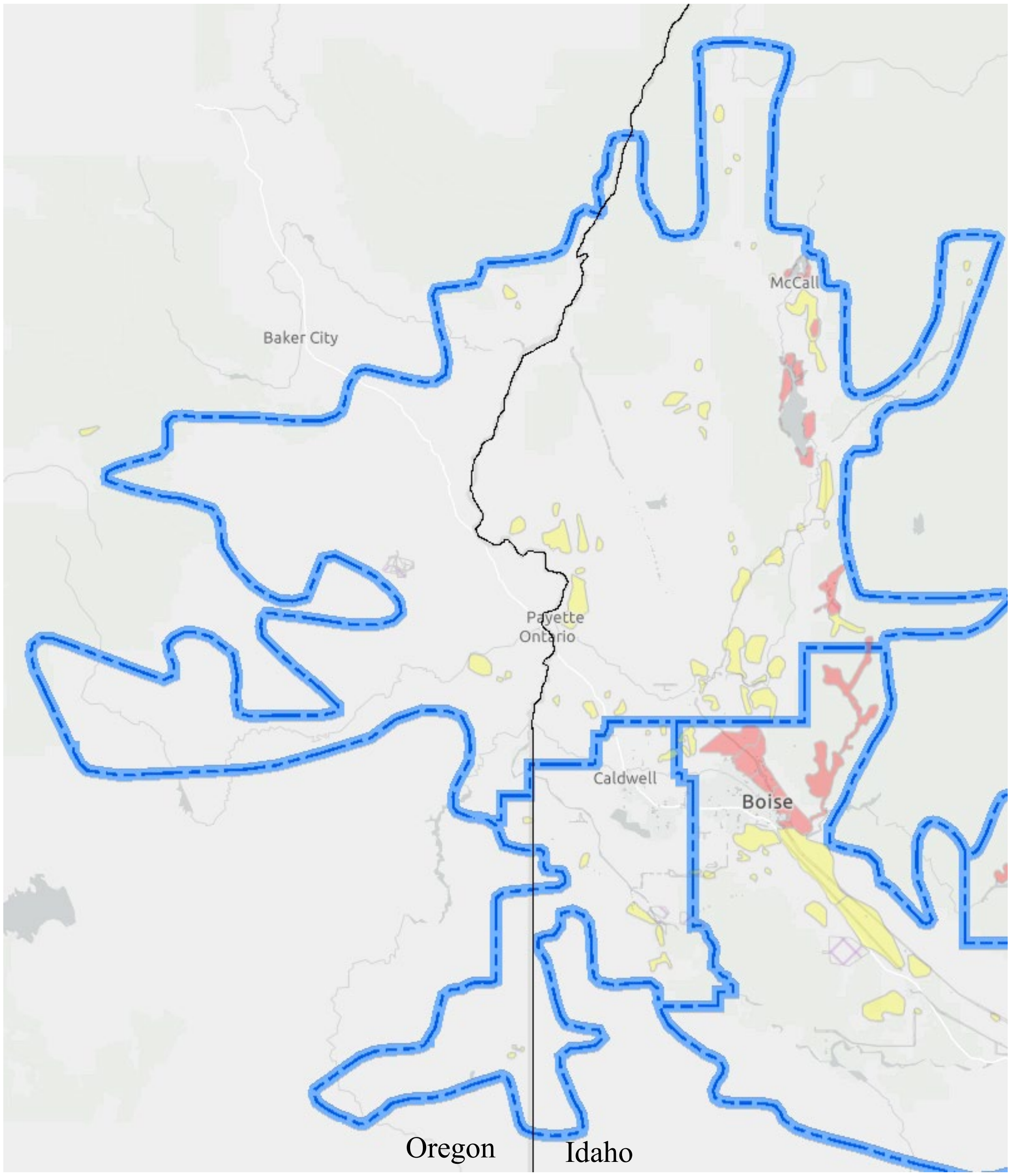
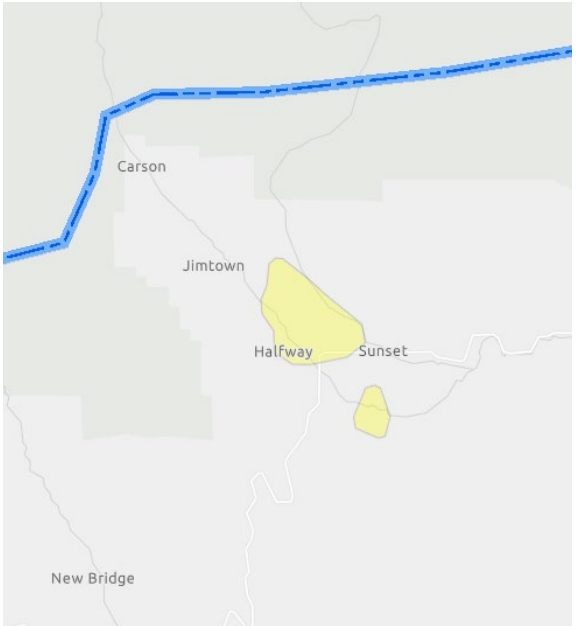
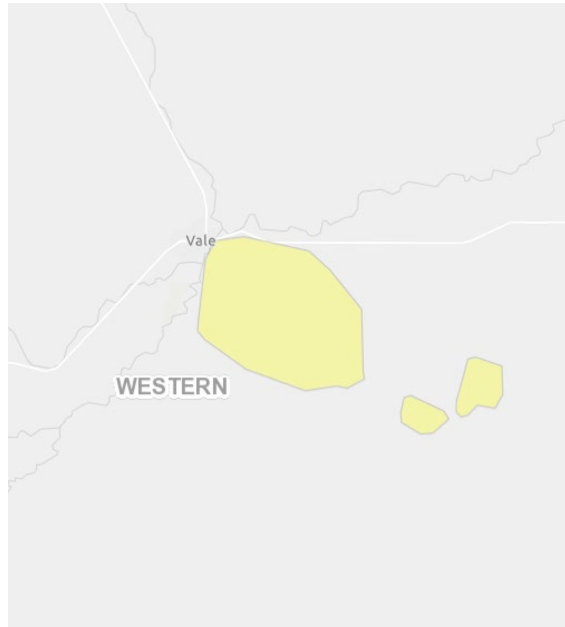


Figure 8
Wildfire Risk Map—western Idaho and eastern Oregon

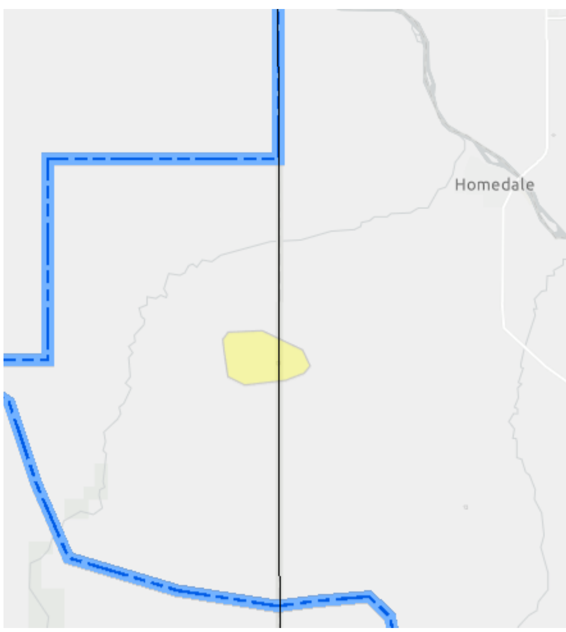
Halfway



Vale



Idaho-Oregon Boarder



Jordan Valley

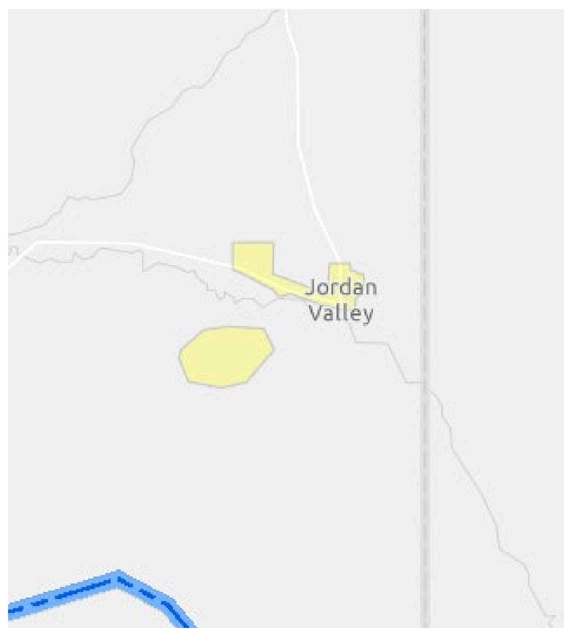


Figure 9
Oregon-specific zones

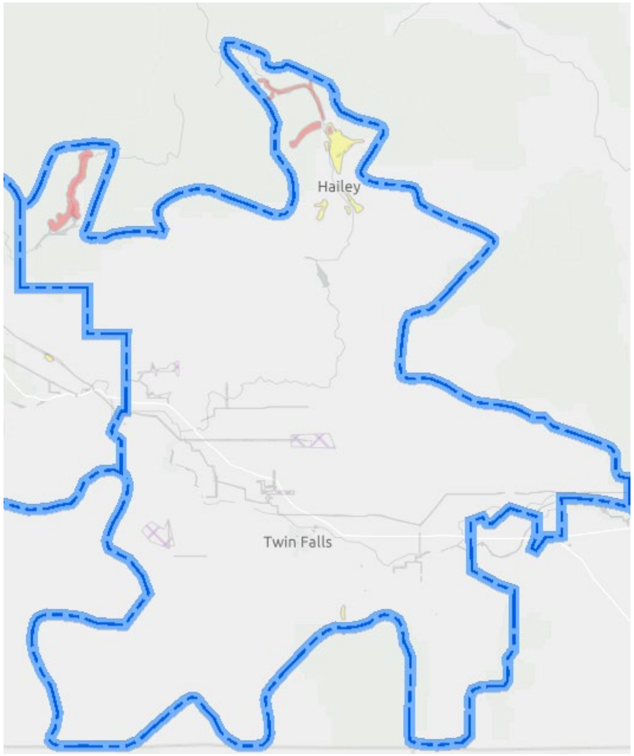
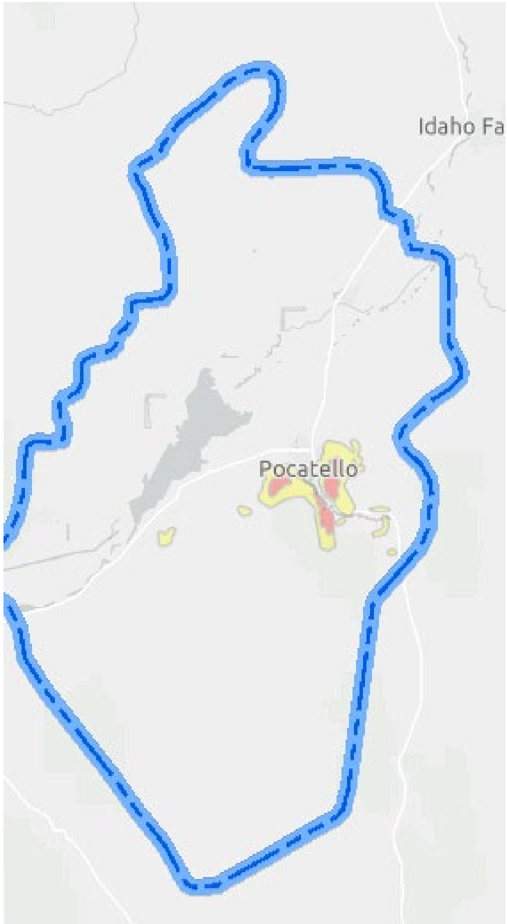


Figure 10
Wildfire Risk Map—southern Idaho

Pocatello



Salmon

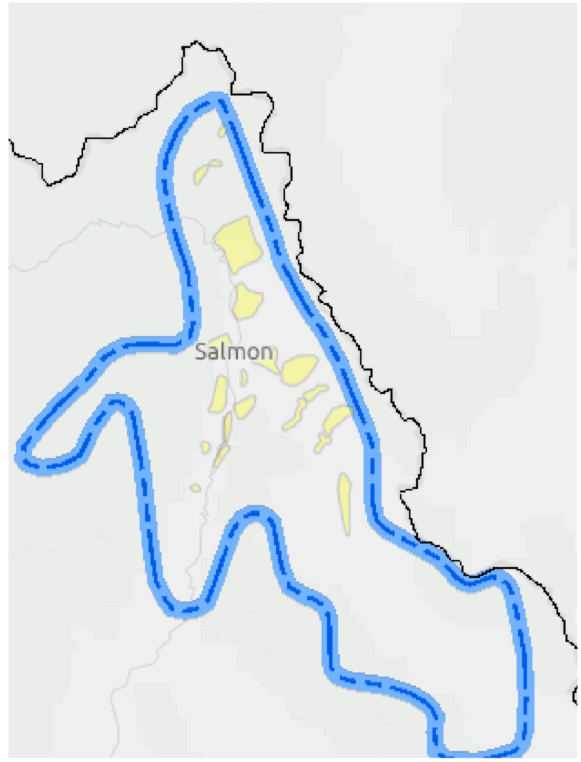


Figure 11
Wildfire Risk Map—eastern Idaho

3.2.2.1. Boardman to Hemingway Proposed Transmission Line

Idaho Power specifically considered the proposed route of the B2H 500 kV transmission line as part of the WMP. The proposed B2H route was included in the wildfire risk assessment and associated map analysis (see Figure 3). Two locations are identified along the route as having increased wildfire risk (YRZs), and there were no areas of higher risk (RRZs). Although the B2H transmission line has not been constructed as of the publication of this 2023 WMP, Idaho Power intends this WMP (as it will be reviewed annually) will apply to B2H. Additionally, Idaho Power will continue to update its fire risk mapping periodically and address the locations with elevated risk consistent with the mitigation strategy for transmission lines as described in sections 5–9 of this WMP.

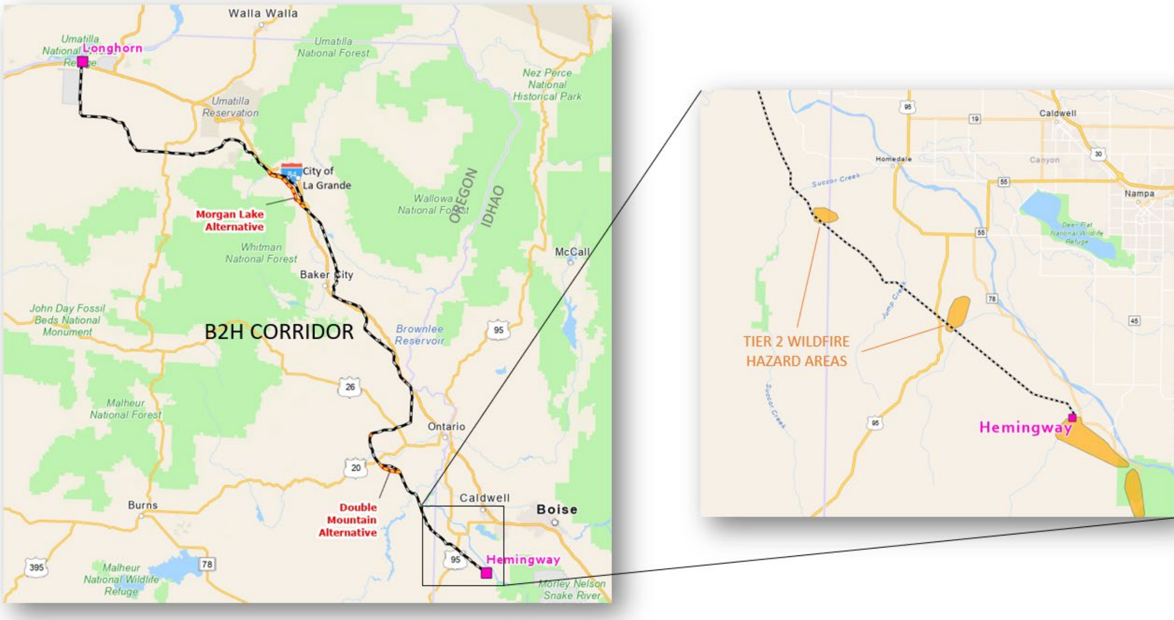


Figure 12
B2H proposed route risk zones

4. Costs and Benefits of Wildfire Mitigation

4.1. Objective

This section details Idaho Power's assessment of high-level risk with respect to undertaking wildfire mitigation activities. This assessment provides a framework for understanding the potential consequences of wildfire damage and the possibility of diminishing those consequences through targeted mitigation activities.

To that end, Section 4.3 identifies selected mitigation activities and the estimated costs of those activities on a system level. In Section 4.4, each mitigation activity is discussed in detail, with an assessment of why it was selected, what alternatives (if any) may be available, and any additional benefits (referred to as "co-benefits") the company believes may result from pursuing it.

4.2. Risk-Based Cost and Benefit Analysis of Wildfire Mitigation

In assessing the probability and consequence of wildfire risk, and to identify benefits of various wildfire mitigation efforts, Idaho Power engaged with its external consultant and considered several sources of empirical data on the costs of major wildfires—both in terms of fires that burn into Idaho Power's facilities or that originate from electric infrastructure. These costs can include replacement costs of the company's property; the cost of fire suppression and environmental damage; third-party claims for property damage; employee and public injuries and fatalities; and other economic losses.

Through its research, Idaho Power found that obtaining a precise calculation of the potential costs of future wildfires is not realistic. The damage that any fire may cause depends on factors such as wind and weather, vegetation, fire risk levels, location, and population and structure density.

Idaho Power's assessment of the potential costs of wildfires—used in developing the WMP and the scope of proposed updates to practices—involved a review of prior major fires in other states, as well as calculations by other western utilities. While this assessment did not yield a precise quantification of potential benefits specific to Idaho Power, it provides a helpful illustration of the potential costs of not taking actions aimed at reducing wildfire risk.

Idaho Power reviewed and considered calculations analyzing the potential reduction in probability of igniting wildfires based on risk-mitigating activities. For instance, in a June 2020 filing before the IPUC, Avista Corporation (Avista) stated that its "analysis indicates a 10-year inherent potential risk exposure of at least $8 billion dollars," though noted the figure should not be interpreted as a precise financial estimate.[11] Avista further noted that the actions it proposes in its own wildfire resiliency plan result in an average percentage of risk mitigation of 89% for the overall plan.[12]

In California, costs and damages associated with wildfires in recent years have exceeded $10 billion per year, with those associated with the 2020 fires alone potentially set to exceed $20 billion.[13] This increase[14] is consistent with the fact that, with few exceptions, the prevalence, intensity, and impact of wildfires continues to escalate year after year as evidenced by information compiled by the California Department of Forestry and Fire Protection (CAL FIRE) and detailed in Table 5.

Table 5
CAL FIRE wildfire data by year

Year	Estimated Acres Burned	No. of Wildfires	No. of Confirmed Fatalities	No. of Structures Damaged or Destroyed
2020	4,197,628	9,279	31	10,488
2019	259,823	7,860	3	732
2018	1,975,086	7,948	100	24,226
2017	1,548,429	9,270	47	10,280
2016	669,534	6,954	6	1,274

The data compiled by peer utilities, historic fire costs, and known damage from prior fires are instructive. Considering peer metrics and analyses on probability and magnitude, as well as Idaho Power's own empirical review of wildfire events such as those in California and Oregon—and the resulting loss of lives—it is reasonable to conclude that the potential human and capital costs and damage from wildfire events vastly exceed any incremental costs of wildfire mitigation efforts identified in this WMP.

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[11] *In the Matter of Avista Corporation's Application for an Order Authorizing Accounting and Ratemaking Treatment of Costs Associated with the Company's Wildfire Resiliency Plan,* Case No. AVU-E-20-05, Application at 17.

[12] Ibid.

[13] Jill Cowan, *How Much Will the Wildfires Cost?*, The New York Times, Sept. 16, 2020, at https://www.nytimes.com/2020/09/16/us/california-fires-cost.html.

[14] Idaho Power believes that its system is in notably better condition than some utilities in California. Nevertheless, these figures illustrate the destruction that can occur from vegetation contact if vegetation is not actively managed.

2023 Wildfire Mitigation Analysis Framework

In 2022, Idaho Power reviewed the risk management process used in developing previous versions of the WMP. The review consisted of reexamining existing risk management practices, specifically how risk is analyzed, evaluated, treated, and continuous improvement is applied. We also benchmarked against other western utilities' risk management approaches and consulted with risk management professionals, both internal and external to Idaho Power.

A formalized risk management process will provide greater structure and consistency in decision making, continuous improvement, and maturing our analytical approach to balancing costs and mitigation benefits. As part of this work, the company determined that the international standard ISO 31000 is widely used by other utilities as a guide or foundation for their WMPs and was recommended to be incorporated by risk management professionals. The ISO 31000 is one of several guides to effective risk management and much of the processes used to create previous versions of the WMP align with the recommended practices found in the standard. However, the ISO 31000 provides a more comprehensive approach to risk management than what was being employed prior and will be integrated into the plan in 2023. This effort will start by performing the following:

- Engage Idaho Power stakeholders to participate in risk review processes and activities with the goal that all employees become managers of risk
- Develop a comprehensive picture of all risk management activities associated with the WMP and how they compare to the ISO 31000
- Determine how the ISO 31000 principles can be applied, achieved, measured, and tracked
- Develop a framework based on the ISO 31000 that provides a structured and effective approach to managing wildfire-related risk and includes a process of reviewing and maturing the methods used for risk identification, analysis, evaluation, and treatment

4.3. Wildfire Mitigation Cost Summary

From 2022–2025, Idaho Power estimates investing $46.8 million in incremental operations and maintenance (O&M) expenses to further wildfire mitigation measures. The following table summarizes the company's planned expenditures associated with executing its WMP through 2025. Estimated amounts reflect the company's best estimates and plans as of the 2022 WMP. These estimates will likely change in the future as the company reviews and refines its WMP and associated mitigation activities. For the 2022 WMP, each wildfire mitigation category—and associated estimated expenditures in Oregon and Idaho—is discussed in Section 4.4.

Table 6
Estimated system-wide incremental O&M expenses for wildfire mitigation, $000s (2023–2025)[15]

	2023	2024	2025	Idaho Power System Total 2023 - 2025
A. Quantifying Wildland Fire Risk				
Risk Map Updates	$ 67	$ -	$ 69	$ 136
B. Situational Awareness				
Weather Forecasting - System development and support	$ 47	$ 74	$ 74	$ 195
Weather Forecasting Personnel - Fire Potential Index (FPI) and Public Safety Power Shutoff (PSPS)	$ 178	$ 99	$ 102	$ 379
Weather Forecasting - Weather Station Maintenance	$ 19	$ 24	$ 30	$ 73
Pole Loading Modeling & Assessment (Contract service)	$ 75	$ 75	$ 75	$ 225
Cameras	$ 165	$ 220	$ 220	$ 605
C. Mitigation - Field Personnel Practices				
Tools/Equipment	$ 5	$ 5	$ 5	$ 15
Mobile Weather Kits for Field Observers	$ 10	$ -	$ -	$ 10
International Wildfire Risk Mitigation Consortium	$ 40	$ 40	$ 40	$ 120
D. Mitigation - Transmission & Distribution Programs				
O&M Component of Capital Work	$ 61	$ 60	$ 54	$ 175
Annual O&M T&D Patrol Maintenance Repairs	$ 50	$ 50	$ 50	$ 150
Environmental Management Practices	$ 25	$ 25	$ 25	$ 75
Transmission Thermography Inspection Mitigation - Red Risk Zon	$ 20	$ 20	$ 20	$ 60
Distribution Thermography Inspection Mitigation - Red Risk Zone	$ 30	$ 30	$ 30	$ 90
Thermography Technician Personnel	$ 160	$ 165	$ 170	$ 495
Transmission Wood Pole Fire Resistant Wraps - Red Risk Zone	$ 88	$ -	$ -	$ 88
Transmission Wood Pole Fire Resistant Wraps - Yellow Risk Zone	$ 163	$ 163	$ 163	$ 489
Wildfire Mitigation Program Manager	$ 191	$ 196	$ 202	$ 589
Covered Wire Evaluation - Pilot Program in PSPS Zones	$ 50	$ 50	$ -	$ 100
E. Vegetation Management				
Transition to/Maintain 3-year Vegetation Management Cycle	$ 11,196	$ 13,347	$ 12,172	$ 36,715
Enhanced Practices for Distribution Red & Yellow Risk Zones (Pre-Fire Season Patrols/Mitigation, Pole Clearing, Removals, Work QA)	$ 1,284	$ 1,349	$ 1,416	$ 4,049
Line Clearing Personnel	$ 159	$ 164	$ 169	$ 492
Fuel Reduction Program	$ 75	$ 75	$ 75	$ 225
Vegetation Mgmt Satellite and Aerial patrols	$ 150	$ 300	$ 300	$ 750
F. Communications				
Wildfire/Wildfire Mitigation Education/Communication - Advertisements, Bill Inserts, Meetings, Other	$ 100	$ 100	$ 100	$ 300
PSPS Customer Education/Communication - Advertisements, Bill Inserts, Other	$ 71	$ 71	$ 71	$ 213
G. Information Technology				
Communication/Alert Tool for PSPS Customer Alerts/Extended Use	$ 129	$ 129	$ 129	$ 387
Forecast Incremental O&M Expenditures Total	**$ 14,608**	**$ 16,831**	**$ 15,761**	**$ 47,200**

[15] As of December 29, 2022.

4.4. Mitigation Activities

Idaho Power selected individual wildfire risk mitigation activities based on a variety of factors, including assessment of industry best practices in wildfire mitigation; discussions with peer utilities; consultation with government entities and agencies; and with consideration of alternatives that could be pursued.

Below is a narrative of each mitigation activity, its purpose, estimated near-term cost, potential co-benefits of the activity to Idaho Power and its customers, and potential alternatives.

With respect to Idaho and Oregon cost estimates, the estimated costs identified below are grounded in cost assignment between the company's Idaho and Oregon service areas and further informed by anticipated work in the two service areas.

4.4.1. Quantifying Wildland Fire Risk

Idaho Power's assessment of wildland fire risk is discussed in Section 3 of this WMP.

The first step in developing Idaho Power's WMP was to conduct a comprehensive assessment of the company's service area and transmission corridors. The company worked with Reax Engineering, a consulting firm that specializes in wildfire risk modeling and fire science, to conduct Idaho Power's wildfire risk analysis. The company determined that hiring an external consultant was beneficial for two reasons: (1) an external consultant was more cost effective than hiring additional resources within Idaho Power to perform the modeling, and (2) an outside consultant helped ensure Idaho Power's risk analysis approach was similar to its peer utilities.

An additional co-benefit of hiring an external consultant is aligning risk analysis with other utilities' practices to create a basis for comparison of risk and also a standard terminology and methodology in discussing risk. Idaho Power deemed Reax Engineering a qualified consultant to perform wildfire risk analysis based on the work it performed for the CPUC in developing the CPUC Fire Threat Map. Other utilities in Oregon, Idaho, Nevada, and Utah have utilized similar modeling approaches to identify and quantify wildfire risk.

Cost Estimate for Quantifying Wildland Fire Risk (2023–2025)

Idaho Power intends to re-evaluate its risk analysis using an external consultant on two more occasions between 2023 and 2025. Idaho Power estimates system-wide expenditure for these services to be approximately is $136,000.

4.4.2. Situational Awareness—Weather Forecasting Activities and Personnel

Idaho Power discusses specific situational awareness practices in Section 5 of this WMP.

In developing the WMP, Idaho Power created a new Fire Potential Index (FPI) tool to support operational decision-making to reduce wildfire threats and risks. The tool takes data on weather, prevalence of fuel (i.e., trees, shrubs, grasses), and topography, and converts that data into an easily understood forecast of the short-term fire threat for different geographic regions in Idaho Power's service area. Additionally, Idaho Power plans to continue to enhance meteorological and weather forecasting capabilities to further improve FPI forecasting and help determine when a Public Safety Power Shutoff may be necessary in Idaho Power's service area.

The benefits of developing the FPI and enhancing the company's meteorological forecasting capabilities is greater situational awareness of Idaho Power's system during critical peak summer months. To continue to generate useful information and system benefits, Idaho Power's situational awareness activities will be evaluated and updated annually as necessary to support the company's wildfire preparedness.

The company considers the FPI and related efforts an essential part of reducing the risk of ignition from work activities. This provides Idaho Power field personnel would not have a tool to assess the fire potential on a consistent basis. Given the distinct benefits that result from the FPI and enhanced foresting capabilities, Idaho Power did not consider alternatives to the development of these critical tools.

Cost Estimate for Situational Awareness—Weather Forecasting Activities and Personnel (2023–2025)

The estimated expenditure for weather forecasting activities (weather forecasting tools, system development, weather station maintenance, and personnel) is $647,000 between 2023 and 2025.

4.4.3. Situational Awareness—Advanced Technologies

Beginning in 2022, Idaho Power created a Technology Strategy Initiative team aimed at determining how new technologies and innovative practices can be incorporated into the company's wildfire mitigation practices to further decrease wildfire risk. Technology-based practices being considered include—amongst others—strategic use of cameras, satellite, and aerial imagery to detect vegetation hazards, pole loading modeling (to assess the structural integrity of poles), as well as covered conductors. With regard to cameras, the company is evaluating a pilot to test placement of cameras in strategic, high-risk locations to enhance situational awareness. Additionally, the company is learning more about artificial intelligence and how it can be leveraged to detect wildfire ignitions. Multiple camera and analytics companies are being considered to determine potential cost-effective solution(s). The company is also working with local agencies to explore the possibility of partnering on the installation and ongoing use of cameras which may lead to reduced cost.

Cost Estimate for Situational Awareness—Pole Loading Modeling and Assessment (2023–2025)

The estimated system-wide expenditure to conduct pole loading modeling and assessment, which includes LIDAR assessment, is $225,000 for 2023 through 2025. Idaho Power plans to conduct the assessment in its highest risk zones, which are located exclusively in Idaho, as detailed in Table 4.

Cost Estimate for Situational Awareness—Cameras (2023–2025)

The estimated system-wide expenditure for the pilot evaluation installation of cameras in high-risk areas is $605,000 from 2023 through 2025. Idaho Power plans to prioritize the use of cameras in its highest risk zones, which are located exclusively in Idaho as detailed in Table 4.

4.4.4. Field Personnel Practices

Idaho Power discusses its field personnel practices in Section 6 of this WMP.

Idaho Power's wildfire mitigation strategy includes procedural measures to reduce potential ignition and spread of wildfires. Idaho Power developed a *Wildland Fire Preparedness and Prevention Plan* (included as Appendix A to this WMP) to provide guidance to Idaho Power employees and contractors. The plan includes information regarding fire season tools and equipment available on the job site; daily situational awareness relative to areas with heightened fire conditions; expected actions and mechanisms for reducing on-the-job wildfire risk as well as reporting requirements in the event of an ignition; and training and compliance requirements.

All Idaho Power crews, and certain field personnel and contractors performing work on or near Idaho Power's facilities are required to operate in accordance with the provisions of the *Wildland Fire Preparedness and Prevention Plan* and expected to conduct themselves in a fire-safe manner. They should be prepared for wildfire by carrying specific tools, including but not limited to, shovels, Pulaskis,[16] and water for initial suppression. Additionally, Idaho Power's PSPS program (included as Appendix B to this WMP) includes employees acting as Field Observers to report on site conditions as part of the de-energization process. Field Observers are equipped with mobile weather kits that include wind meters, compasses, and satellite communication devices to report real-time conditions.

The preparedness of Idaho Power crews and contractors is critical to comprehensive wildfire risk reduction practices. The incremental investment in field personnel equipment is focused on additional tools carried by employees working in elevated risk zones. Additionally, Idaho Power will join the International Wildfire Risk Mitigation Consortium (IWRMC), a group whose mission is to share lessons learned, best practices, and innovation in the area of wildfire mitigation. Many of Idaho Power's utility peers are part of the consortium. The company is not aware of any other effort or group that provides a similar level of access or insight into global thinking and advancements in wildfire mitigation as the IWRMC.

Cost Estimate for Field Personnel Equipment (2022–2025)

The estimated system-wide expenditure for field personnel equipment (tools, mobile weather kits, and participation in the IWRMC) is $145,000 between 2023 and 2025.

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[16] A Pulaski is a hand tool specifically used for fighting fires that combines an axe and an adze atop a single handle. The tool is the invention of Edward Crockett Pulaski, a ranger with the U.S. Forest Service who was based in Wallace, ldaho, in the early 1900s.

4.4.5. Transmission and Distribution (T&D) Programs for Wildfire Mitigation

Idaho Power's T&D-related wildfire mitigation activities primarily involve expanded asset management programs and system hardening efforts, discussed in detail in Section 8.2 of this WMP. The narratives below provide insight into Idaho Power's consideration and selection of certain mitigation and hardening practices.

4.4.5.1. Annual T&D Patrol, Maintenance, and Repairs

Visual inspections are a critical component of T&D line-related wildfire mitigation efforts. On an annual basis, Idaho Power uses helicopters for visual aerial inspection of transmission lines that are Western Electricity Coordinating Council (WECC) path lines. Under the WMP, Idaho Power will continue to use this method of line inspection for all transmission lines located in Red Risk Zones. Idaho Power strives to complete these inspections prior to the start of the wildfire season; however, spring weather and snow levels may create access issues and delay the completion until June 15 in some areas.

Distribution lines that are located within RRZs are inspected on an annual basis to identify 'Priority 1' defects, or conditions that may result in an outage or potential ignition. The patrols will be completed by personnel that have been trained in distribution line inspection procedures and have experience in distribution line construction. Targeted defects may include cracked/broken crossarms, avian nesting hazards, damaged equipment and hardware, floating conductors, NESC violations, and other obvious defects that pose an immediate threat to the continued operation of the line. Similar to visual inspections for transmission lines, Idaho Power will strive to complete distribution inspections prior to the start of each wildfire season; however, access issues may delay the completion until June 15 in some areas.

Helicopters are not practical for carrying out all distribution patrols due to greater population, structural, and vegetation density, so unmanned aerial vehicles (UAV) with high-definition cameras are used to aid in these inspections in certain situations. These inspections allow personnel to look for potential line defects that may not be obvious from the ground. Priority 1 defects are immediately reported and repaired as soon as possible.

The company will continue to explore the expanded use of UAVs, as the detailed images and data collected through high-resolution aerial inspections can provide several co-benefits, including more granular data on vegetation growth and line and facility conditions.

Cost Estimate for Annual T&D Patrol, Maintenance, and Repairs (2023–2025)

The estimated system-wide incremental expenditure for annual T&D patrols, maintenance, and repairs is $150,000 from 2023 to 2025.

4.4.5.2. Thermography Inspections

While Idaho Power periodically conducts infrared thermography inspections as part of reliability and maintenance programs, the company is expanding these inspections in Red Risk Zones on an annual basis. These inspections are conducted using hand-held and drone-mounted cameras with thermal-sensing technology and can help identify defects associated with the overheating of equipment, connections, splices, or conductors.

As part of the thermography inspections, temperature gradients are analyzed to detect potential problems and issues found are prioritized based on their severity and repaired. Idaho Power recently created a new Thermography Technician position to carry out the inspections and coordinate repair activities, and additional resources may be added to perform this function across more of Idaho Power's service area if a single technician proves insufficient. To prioritize the use and information gained from this technology, it will initially be employed only in RRZs. 2022 is the test year to determine how many inspections can be performed, and the overall cost-benefit of the technology to help evaluate the possibility of expanding use and adding more resources.

Thermography inspections are uniquely valuable in that they are able to uncover problems undetectable to the naked eye. From the company's perspective, there is not a viable alternative to this practice. The technology enables more proactive identification of potential issues than would otherwise be possible.

Cost Estimate for Thermography Inspections (2023–2025)

The estimated expenditure for thermography inspections is $645,000 from 2023 to 2025. Idaho Power will prioritize the use of this mitigation practice in its highest risk zones, which are exclusively in Idaho, as detailed in Table 4.

4.4.5.3. Wood Pole Fire-Resistant Wraps

To help improve the resiliency of the company's wood transmission poles, Idaho Power now wraps them with a fire-resistant mesh in Red and Yellow Risk Zones. The mesh wrap helps protect the integrity of the pole if it is exposed to fire and improves the resiliency of Idaho Power's transmission system. An alternative to installing fire-proof mesh wrap is to replace wood poles with structures made of non-combustible material, such as steel. With 3,863 existing wood transmission poles in Idaho Power's Red and Yellow Risk Zones, the cost of replacing all wood poles is much higher than the cost of covering with a fire-resistant mesh.

Prior to developing the WMP, Idaho Power evaluated different products to determine the most cost-effective approach for protecting existing wood poles from fire. Several products were considered and trialed, including short-term spray-on and paint-on fire retardants, long-term retardants, and steel wraps. In 2020, the company evaluated a protective mesh wrap and compared the cost and performance to the alternatives. The evaluation found that the mesh wrap was approximately 53% less costly than the alternatives and offered the same level of risk reduction. The decision to use a mesh wrap product was not based solely on cost; other criteria were considered, including availability of the product, ease of installation, expected protective life span, and performance when exposed to fire. By all these measures, fire-resistant mesh was the best solution.

Cost Estimate for Wood Pole Fire-Resistant Wraps (2023–2025)

The estimated system-wide expenditure for applying fire-resistant mesh wraps to transmission poles in Red and Yellow Risk Zones is $577,000 between 2023 and 2025.

4.4.5.4. Covered Conductor Pilot

Idaho Power's Technology Strategy Initiative identified covered conductor as a potential mitigation measure to pilot. Benchmarking and feedback from other utilities highlighted the potential benefit of covered conductor as a mitigation measure. The company will conduct a pilot of covered conductor through 2024 to explore the benefits, tooling requirements for field personnel, and design parameters. While covered conductor may reduce the risk of wildfire, the company will analyze potential co-benefits, including improved reliability outside of wildfire season and reduced outage restoration costs.

Cost Estimate for the Covered Conductor Pilot (2023–2024)

The estimated cost of the pilot is $100,000 from 2023–2024. While this pilot will take place in Idaho, the lessons from it will extend across the company's service area.

4.4.6. Enhanced Vegetation Management

Idaho Power's enhanced vegetation management practices are discussed in detail in Section 8.3 of this WMP.

In the initial stage of developing its WMP, Idaho Power conducted an analysis to determine the most likely sources of ignition across the company's service area. Reliability data revealed vegetation contact as one of the most common causes of outages on Idaho Power's system. With the goal of eliminating potential ignition sources and to reduce risk, enhanced vegetation management was recognized as a critical aspect of Idaho Power's WMP.

To prioritize risk reduction from vegetation contact, Idaho Power determined it would move to a three-year pruning cycle and apply enhanced vegetation management practices in Red and Yellow Risk Zones. These enhanced practices include pre-fire season vegetation patrols, more targeted pole clearing and vegetation removal, and additional quality assurance for vegetation management practices.

The company considered other vegetation management alternatives, including shorter trimming cycles, longer trimming cycles, and strategies that evaluate each tree individually and only trim it once it has nearly grown back to the power line (known as "just-in-time trimming"). Each alternative presented challenges or resulted in negative impacts that undermined any potential benefits.

While shorter trimming cycles result in less vegetation being removed during each trimming cycle, this practice costs more due to the need for more resources and more frequent trimming of trees near the power lines. In contrast, longer cycles result in less frequent trimming of each tree but larger amounts of vegetation that must be removed to maintain larger clearance envelopes around the power lines to accommodate additional years of vegetative growth. Further, longer trimming cycles create logistical challenges that are exacerbated by tree biology. Some trees simply grow faster than a given trimming cycle and the longer the trimming cycle, the more pervasive this issue becomes. Longer cycles that call for heavy pruning also lead to hormonal imbalances between a tree's canopy and its root system. To correct this imbalance, the tree aggressively re-grows new sprouts to quickly replace its lost canopy. In this regard, heavier pruning results in a faster rate of tree regrowth than normal, making it even more difficult to consistently maintain longer trimming cycles. Finally, "just-in-time trimming" is primarily a reactive strategy that ultimately leads to challenges associated with securing qualified tree-trimming crews, as this ad hoc approach involves hiring crews on an as-needed basis rather than on a consistent schedule. After evaluating these alternative approaches, Idaho Power concluded that the goal of maintaining a consistent three-year trimming cycle is the most cost-effective and sustainable strategy to keep vegetation away from the power lines in a proactive manner.

Moving forward with a three-year cycle and performing the additional activities detailed above will involve a sizeable increase in incremental O&M expenditure. An alternative to enhancing Idaho Power's vegetation management program is to convert overhead distribution circuits to underground. While undergrounding is used in certain circumstances, undergrounding has generally not been determined to be a cost-effective expense relative to enhanced vegetation management. That said, the company continues to evaluate and implement underground solutions, as appropriate, as part of its WMP hardening efforts detailed below.

Although vegetation management is a sizeable increased wildfire mitigation expense, performing this work is expected to have notable co-benefits, including reduced vegetation-caused outages in Red and Yellow Risk Zones. Idaho Power plans to monitor performance and outage metrics to confirm the success of the enhanced program.

Decreasing vegetation outages was considered one of the most important, cost-effective measures Idaho Power could take to reduce the likelihood of an ignition event and protect utility infrastructure. Shifting vegetation management practices was deemed a prudent course of action based on the number of potential outages or ignition sources that may be eliminated. It is also the approach that has been adopted by many of Idaho Power's peer utilities.

Additionally, the company will participate in a regional fuel reduction program, in which Idaho Power will work in partnership with the Idaho Department of Lands, the National Forest Foundation, the U.S. Forest Service, and the U.S. Bureau of Land Management to remove hazard trees and other vegetation from utility rights-of-way. The partnership is designed to enhance forest resilience to wildfire, decrease hazardous fuel accumulations, increase powerline resiliency while minimizing the risk of ignitions, and improve forest conditions in the vicinity of Idaho Power infrastructure. This program is similar to what other western utilities have taken part in and is modeled after projects performed in Washington, California, Colorado, and Arizona. Participation in the effort is estimated to cost $225,000 through 2025.

The company also plans to deploy satellite and aerial patrols of vegetation in the company's wildfire risk zones. The technology used in these satellite and aerial patrols will help identify encroachment and clearance issues in areas that are growing faster than expected and hazard trees that have the potential of falling into powerlines. Data collected through this technology may reshape the company's vegetation management strategy and shift from a systemwide cycle to a more targeted approach that identifies and focuses on high-growth vegetation areas. The company will conduct limited vegetation-focused satellite and aerial patrols in 2023 before expanding to a larger area in 2024 and 2025, pending outcomes from the pilot program years. The company estimates spending $750,000 on this technology through 2025.

Cost Estimate for Enhanced Vegetation Management (2023–2025)

The estimated system-wide expenditure for enhanced vegetation management is $41.3 million from 2023 to 2025.

4.4.7. Communications and Information Technology Customer Notification Enhancements

Idaho Power's efforts to communicate with customers and the public about wildfire and mitigation are discussed in detail in Section 10 of this WMP.

Idaho Power considers communication a vital part of its wildfire mitigation efforts. Customer and public awareness and education are a vital part of ensuring that the communities that Idaho Power serves are protected and safe from the threat of wildfire. New communication expenses related to customer and community educational outreach include advertisements, printed media, social media, and public meetings. The purpose of these communications is to keep customers aware of mitigation and fire-related activities before, during, and after fire season. Additionally, the company is building out communication systems to be able to alert customers more quickly and easily about wildfire events and outages, including potential PSPS events.

Cost Estimate for Communication and Customer Notification Enhancements (2023–2025)

The estimated system-wide expenditure for communication expenses is $513,000 and $387,000 for customer notification system enhancements, totaling $900,000 from 2023 to 2025.

4.4.8. Incremental Capital Investments

Idaho Power's wildfire mitigation efforts include capital investments in system hardening practices including approaches deployed after internal testing and analysis, many of which also provide co-benefits to the company.

Idaho Power's capital investments for wildfire mitigation are discussed in detail in Section 8.2 (T&D Asset Management Programs) of this WMP.

4.4.8.1. Circuit Hardening and Infrastructure Upgrades

Idaho Power estimates spending $5.1 million annually through 2025 on circuit hardening and infrastructure upgrades across its system.

Idaho Power's WMP includes an overhead distribution hardening program for Red Risk Zones. The program includes systematic replacement of hardware, equipment, and materials to improve safety and reliability and reduce ignition risk. The first five years of the program are focused on circuits in Red Risk Zones, but it may be expanded to Yellow Risk Zones in the future. The company will review hardening outcome metrics annually to determine the benefit of the program and to determine whether to expand the program after 2025.

Prior to developing its WMP, Idaho Power successfully implemented many of the same hardening measures detailed below as part of the company's reliability program. Outage data and analytics showed that customer outages were reduced by approximately 38% in areas where hardening projects were carried out. With the success of reducing outages, some of these same activities to increase reliability were chosen to be part of the WMP to help reduce ignition potential in Red Risk Zones. Enhanced system hardening efforts include installation of fire safe fuses, Spark Prevention Units, and fiberglass crossarms.

All the hardening activities and equipment identified in this program were evaluated by patrolmen, troublemen, reliability engineers, and the company's Methods and Materials department to determine cost-effective solutions that balance overall costs with expected risk reduction.

As an alternative to conducting circuit hardening upgrades, the company considered converting overhead distribution circuits to underground. While underground conversions are used in certain circumstances, the cost is estimated to be 2–10 times higher than the cost of carrying out hardening work. In general, overhead hardening efforts provide the benefit of being able to impact a greater number of circuit miles and customers in a shorter time horizon with less investment than undergrounding. Idaho Power will continue to evaluate underground opportunities as part of overall system hardening efforts.

The following summarizes the incremental capital investments the company is making to harden its system and further reduce wildfire risk:

Wood Pole Replacement—The company will replace wood poles if field evaluations determine that significant deterioration or damage has occurred since the last inspection or treatment. Poles are inspected above the groundline to determine strength and climbability. Poles identified as "rejects" will be replaced. Furthermore, poles having wood stubs/structural reinforcements are changed out pursuant to current practices.

Fuse Replacements—Expulsion fuses located in Red Risk Zones will be changed out with energy-limiting and power fuses. Fuse applications include overhead transformers, line taps, risers, and capacitor banks. In 2018, Idaho Power began exploring different fusing technology to replace expulsion fuses with non-expulsion fuses. Three different fuse types were considered and subsequently piloted. The pilot was used to determine the performance of each fuse type, installation requirements, and coordination characteristics. Financial analysis included the cost of each fuse along with associated cutout and hardware and helped determine the most cost-effective option. This information was used to evaluate non-expulsion fuses. *Replacement of all expulsion fuses in Red Risk Zones is expected to take* *approximately three years at a cost of approximately $1.9 million. Because this work will be conducted in Red Risk Zones, the company does not anticipate replacing fuses in Oregon at this time.*

Spark Prevention Units—Porcelain arresters used for overvoltage protection will be changed out with arresters utilizing Spark Prevention Units (SPU). The SPU acts to eliminate the potential of catastrophic failure during arrester operation. This work includes all distribution arresters located on primary distribution lines in Red Risk Zones. In 2019, Idaho Power piloted new arrester technology to determine performance characteristics, installation requirements, and potential benefits in reducing ignition risk. As part of the pilot, Idaho Power compared different manufacturers with similar technology and conducted performance analysis to determine the most cost-effective solution. *Replacement of the arresters is expected to take approximately three years to complete and will cost approximately $1.7 million. Because this work will be conducted in Red Risk Zones, the company does not anticipate replacing arrestors in Oregon at this time.*

Fiberglass Crossarms—Idaho Power began piloting fiberglass crossarms in 2018 to determine potential cross-functional benefits associated with fiberglass. The pilot focused on cost, ease of installation, strength, supply availability, and reduced potential for tracking of electrical current. Tracking is known as the flow of current over an insulator, which can generate heat. The company compared different crossarm types and manufacturers and determined that fiberglass was most cost effective when considering up-front capital and installation costs. The pilot program, along with benchmarking of peer utilities, helped determine that fiberglass crossarms provided a number benefits relative to improved safety and reliability. Therefore, Idaho Power's hardening program includes the installation of both tangent and dead-end fiberglass crossarms in Red Risk Zones. However, Idaho Power does not intend to replace all wood crossarms with fiberglass immediately. As part of the fielding phase, company distribution designers will assess wood crossarms and initially change those showing signs of defects or damage. Identified crossarms utilizing wood pins will also be replaced with fiberglass. This approach will spread the cost out over time and help reduce the upfront cost of the program.

Small Conductor—In the early stages of developing the WMP, Idaho Power considered the possible risk associated with small conductor and the potential for breakage. As a result of this exercise, the company's WMP hardening program includes the replacement of overhead distribution conductor that meets certain criteria which includes approximately 60 miles in Red Risk Zones. Conductor losses were analyzed and showed that replacing the conductor will result in an approximately 50% reduction of line losses, resulting in co-benefits for the company and customers in terms of greater reliability and line loss improvements.

Porcelain Switches—Idaho Power's Outage Management System and feedback from field personnel revealed potential benefits of switches made of material other than porcelain. Therefore, porcelain switches installed in Red Risk Zones will be changed out with cutouts featuring Ethylene Propylene Diene Monomer Rubber (EPDM). Idaho Power's Methods and Materials Department trialed different cutout switches made up of different material, including silicone and polymer, to determine the most cost-effective solution. The results of the trial highlighted the potential for avian issues with silicone (i.e., ravens tended to eat the silicone), and the cost of EPDM versus polymer was nearly equivalent. The financial analysis determined that EPDM would preserve the integrity of the insulator body, prevent outages, and provide an estimated savings of $10,798 per year over silicone.

Avian Protection—Idaho Power employs several different protection measures to protect wildlife on existing structures including but not limited to covers, insulated conductor, diverters, perches, nesting platforms, and structural modifications. The company has an extensive history working with manufacturers of animal guards/covers and regularly seeks new solutions for avian issues to prevent mortalities, increase reliability, and eliminate other risks. The company's Avian Protection Plan (APP) was developed in the mid-2000s and many of the practices identified in the APP are used for wildfire mitigation in Red and Yellow Risk Zones. For example, new wildlife guards were recently developed and installed in conjunction with the installation of new power fuses and SPUs. Idaho Power consulted with different manufacturers to develop new products that would accomplish the dual goals of avian protection and wildfire mitigation. The best solution is determined on a case-by-case basis depending on the specific location, the type and extent of avian presence, and other relevant factors.

4.4.8.2. Overhead to Underground Conversions

Another aspect of Idaho Power's system hardening program is the select conversion of overhead to underground distribution lines in Red Risk Zones. In 2022, the company will convert 1.5 miles of overhead distribution lines to underground lines. In 2023 and beyond, the company will work to build a strategic undergrounding program to weigh the cost-benefit of undergrounding versus other circuit hardening measures. While underground distribution lines offer benefits associated with being less exposed to the elements and external forces, conversion may not be possible, advisable, or economical in certain situations. The company will continue to evaluate the feasibility of underground conversions as well as the relative value and cost effectiveness as part of the WMP.

4.4.8.3. Transmission Steel Poles

In 2021 and as part of its WMP, Idaho Power revised its transmission construction standards to utilize steel poles and structures for new line construction built to 138 kV and above in elevated wildfire risk zones. This change is intended to minimize the potential for wildfire damage, improve transmission line resiliency, and increase reliability for customers. Wood poles continue to be accepted and used in the industry, and the company will still utilize wood poles in many transmission system applications in consideration of the availability of steel poles, the specific engineering, right-of-way, permitting, and scheduling requirements for each project.

In addition, wood poles will continue to be the standard construction practice for transmission line voltages below 138 kV unless a different material is needed to meet specific engineering or planning requirements. As discussed above, Idaho Power will wrap wood poles located in Red and Yellow Risk Zones with fire-proof mesh.

5. Situational Awareness

5.1. Overview

Visibility and readily available access to current and forecasted meteorological conditions and fuel conditions is a key aspect of Idaho Power's wildfire mitigation strategy. Meteorological and fuel conditions can vary significantly across Idaho Power's service area. Idaho Power leverages its internal atmospheric science department's modeling/forecasting capabilities, its existing field weather stations, and publicly available weather/fuel data to develop projections of current and future wildfire potential across Idaho Power's service area. This wildfire potential information is then available to operations personnel to factor into their operational decision-making.

5.2. Fire Potential Index

Idaho Power has developed an FPI tool based upon original work completed by San Diego Gas and Electric, the National Forest Service, and the National Interagency Fire Center and modified for Idaho Power's Idaho and Oregon service area. This tool is designed to support operational decision-making to reduce fire threats and risks. This tool converts environmental, statistical, and scientific data into an easily understood forecast of the short-term fire threat which could exist for different geographical areas in the Idaho Power service area. The FPI is issued for a seven-day period to provide for planning of upcoming events by Idaho Power personnel.

The FPI reflects key variables, such as the state of native vegetation across the service area ("green-up"), fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value and those individual numeric values are summed to generate a Fire Potential value from zero to sixteen, each of which expresses the degree of fire threat expected for each of the 7 days included in the forecast. The FPI scores are grouped into the following index levels:

- **Green**: FPI score of 1 through 11 indicates low potential for a large fire to develop and spread as there is normal vegetation and fuel moisture content as well as weak winds and high relative humidity.
- **Yellow**: FPI score of 12 through 14 indicates an elevated potential for a large fire to develop and spread as there are lower than normal vegetation and fuel moisture content as well as moderate winds and lower than normal relative humidity.
- **Red**: FPI score of 15 through 16 indicates a higher potential for a large fire to develop and spread as there are well below normal vegetation and fuel moisture content as well as strong winds and low relative humidity.

Fire Potential Index (FPI) Category			
	Normal	Elevated	High
FPI Range	1 to 11	12 to 14	15 - 16

The state of native grasses and shrubs, or **Green-Up Component**, of the FPI is determined using satellite data for locations throughout the Idaho Power areas of interest. This component is rated on a 0-to-5 scale ranging from very wet (or "lush") to very dry (or "cured"). The scale is tied to the Normalized Difference Vegetations Index (NDVI), which ranges from 0 to 1, as follows:

Green-Up Component						
NDVI	Very Wet/Lush: 1.00 to 0.65	0.64 to 0.60	0.59 to 0.55	0.54 to 0.50	0.49 to 0.40	Very Dry/Cured 0.39 to 0.00
Score	0	1	2	3	4	5

The **Fuels Component (FC)** of the FPI measures the overall state of potential fuels which could support a wildfire. Values are assigned based on the overall state of available fuels (dead or live) for a fire using the following equation:

FC = FD / LFM

Where FC represents Fuels Component in the scale below, FD represents 10-hour Dead Fuel Moisture (using a 1-to-3 scale), and LFM represents Live Fuel Moisture (percentage). This data will be collected from satellite sources and regional databases supported by state and federal agencies.

The product of this equation represents the fuels component that is reflected in the FPI as follows:

Very Wet					Very Dry
0	1	2	3	4	5

The **weather component** of the FPI represents a combination of sustained wind speeds and dew-point depression as determined using the following scale. Regional adjustment to criteria limits for the upper wind speeds may occur after further discussion with subject matter experts from each of the regional operations. This data will be sourced from the weather, research and forecasting (WRF) products produced by Idaho Power using its High-Performance Computing (HPC) system. In addition to the HPC system produced WRF data, several national level meteorological products will be used. These products will include regional weather observations used to validate model information.

Dewpoint Depression/Wind	≤5 mph	6 to 11 mph	12 to 18 mph	19 to 25 mph	26 to 32 mph	≥33 mph
≥50ºF	4	4	4	5	5	6
40ºF to 49ºF	3	3	4	4	5	5
30ºF to 39ºF	3	3	3	4	4	5
20ºF to 29ºF	3	3	3	3	3	4
10ºF to 19ºF	2	2	2	2	2	3
<10ºF	0	1	1	1	1	2

5.3. FPI Annual Process Review

The FPI process will be reviewed annually after completion of the fire season and, with consultation of interested parties (e.g., Load Serving Operator, Line Crews, and others), will be updated to enhance Idaho Power's wildfire preparedness.

6. MITIGATION—FIELD PERSONNEL PRACTICES

6.1. Overview

A component of Idaho Power's wildfire mitigation strategy is to prevent the accidental ignition and spread of wildfires due to employee work activities. Idaho Power developed the *Wildland Fire Preparedness and Prevention Plan* (Appendix A) to provide guidance to Idaho Power employees and contractors to help prevent the accidental ignition and spread of wildfires due to company work activities in locations and under conditions where wildfire risk is heightened. All Idaho Power crews and certain field personnel performing work on or near Idaho Power's facilities are expected to operate in accordance with the Plan and continue to conduct themselves in a fire-safe manner.

6.2. Wildland Fire Preparedness and Prevention Plan

The *Wildland Fire Preparedness and Prevention Plan* informs Idaho Power personnel and its line construction contractors about the following factors:

- Annual fire season tools and equipment to be available when on the job site
- Daily situational awareness regarding locations of heightened potential for fire risk and weather conditions in those areas
- Expected wildfire ignition prevention actions while working and reporting instructions in the event of fire ignition
- Training and compliance requirements

7. MITIGATION—OPERATIONS

7.1. Overview

A component of Idaho Power's wildfire mitigation strategy is to continue safe and reliable operation of its T&D lines while also reducing wildfire risk. These operational practices primarily center around the following:

- Temporary operating procedures for transmission lines during the fire season[17]
- An operational strategy for T&D lines during time periods of elevated wildfire risk during the fire season
- A PSPS strategy for Idaho Power's service area and transmission corridors

7.2. Operational Protection Strategy

Operational protection strategies were developed to reduce the probability of ignition during fault events on Idaho Power's transmission and distribution system. Analysis was performed by Reliability Engineers to assess the available fault energy under different protection schemes and configurations and the effect each would have on customers in terms of increased and extended outages. Idaho Power analyzed the following configurations for automatic reclosing devices:

- Reclose off
- Limited energy reclose
- Limited energy lockout

The analysis performed included assessing Time Current Curves and fault energy of different circuits to gauge the overall reduction in energy between different protection configurations and coordination challenges. Figure 13 below summarizes the different protection configurations evaluated along with estimated benefits in terms of reduced fault energy and impacts to customers. At this time, reclose off appears to provide the best balance between reducing fire ignition risk and customer reliability impacts.

This analysis, along with consideration of historic outage events associated with reclose off, led to the determination that enhanced protection strategies were warranted only in RRZs due to their higher level of wildfire risk. Idaho Power plans to evaluate the effectiveness of protection strategies and will work to mature in this area. New advancements in relay protection used to decrease wildfire risk were evaluated in 2022. The company plans to further our understanding

[17] The duration of the fire season will be reviewed and defined annually.

of their capabilities and integration into existing relay apparatus by testing new algorithms and schemes as part of the company's wildfire technology roadmap from 2024 through 2028.

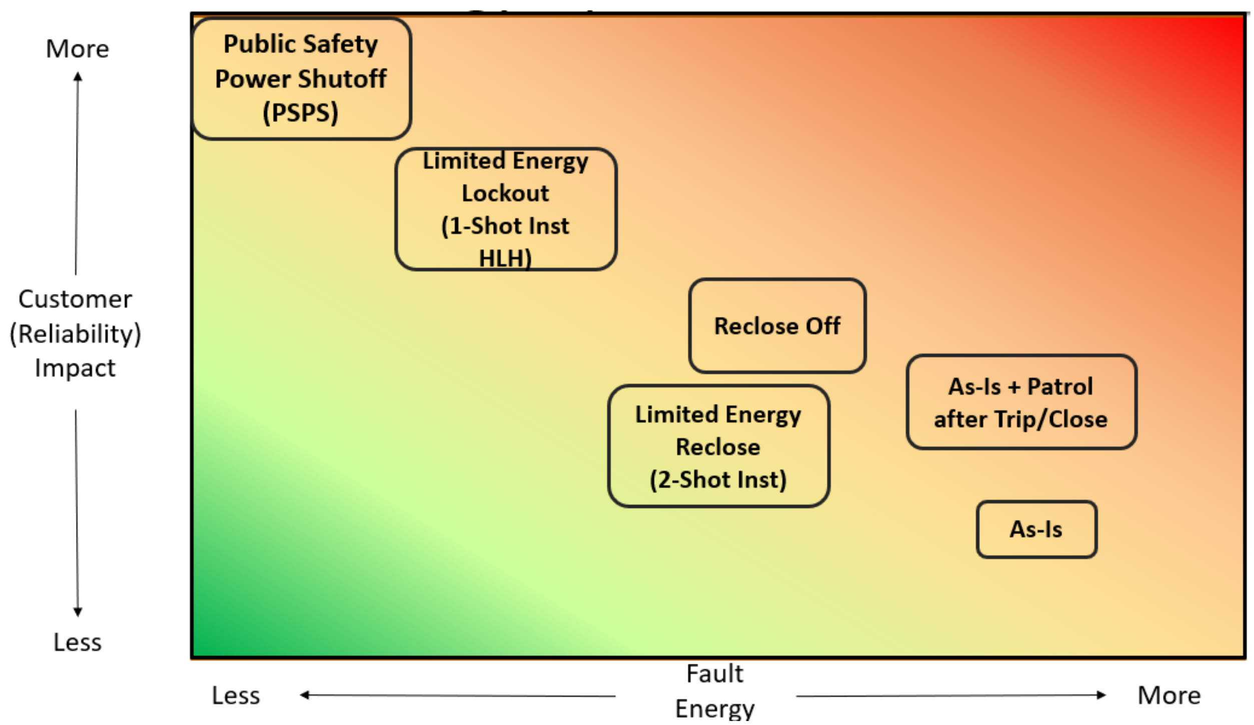


Figure 13
Comparison of reclosing strategies with respect to customer reliability and wildfire risk

7.3. Transmission Line Operational Strategy

7.3.1. Fire Season Temporary Operating Procedure for Transmission Lines

Each year, typically in May, leadership within Idaho Power's Load Serving Operations (LSO) department updates and issues its Fire Season Temporary Operating Procedure. The purpose of this temporary operating procedure is to provide LSO employees with guidelines for operating transmission lines during the summer fire season. The procedure aims to reduce wildfire risk through practices relating to information collection, notification, and procedures for testing/closing in on locked-out transmission lines.

7.3.2. Red Risk Zone Transmission Operational Strategy

During wildfire season, Idaho Power determines a daily FPI as described in Section 5 of this WMP. The FPI informs the transmission line operational strategy for those lines owned, operated, and located in RRZs. These lines will be operated in normal settings mode but with no "testing"[18] of a line that may have "locked out" during the time of a red FPI. Essentially, in the event of a fault on the specified transmission line(s) during a red FPI, the line will operate as normal and may "lock out," at which time the line(s) will either need to be patrolled before "testing" or wait until the FPI level drops out of the red category prior to being reenergized.

7.4. Distribution Line Operational Strategy

7.4.1. Red Risk Zone Distribution Operational Strategy

During wildfire season, Idaho Power determines a daily FPI as described in Section 5 of this WMP. The FPI informs the distribution line operational strategy for those lines located in the wildfire RRZs. These lines will be operated in a non-reclosing[19] state during the time of red FPI. Essentially, in the event of a fault on the specified distribution line(s) during the red FPI, the line(s) will be automatically de-energized with no reclosing attempts until either the line(s) has been patrolled or the FPI level drops out of the red category.

7.5. Public Safety Power Shutoff

7.5.1. PSPS Definition

PSPS, as used in this WMP, is defined as the proactive de-energization of electric transmission and/or distribution facilities during extreme weather events to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. The concept is as follows: if significant weather events can be predicted far enough in advance, the resulting proactive line de-energization before the forecasted weather conditions materialize could mitigate the risk of a wildfire. A PSPS event has significant customer impact and requires significant planning.

PSPS is not the practice of de-energizing lines in the following types of situations:

- Unplanned de-energization of lines required for emergencies and during outage restoration situations.
- Planned line or station work activities that require a planned outage (Idaho Power currently has a planned outage customer notification process in place for this).
- Reactive de-energization of electric transmission and/or distribution facilities, which may be either at Idaho Power's determination or at the request of fire managers (e.g., BLM,

[18] Transmission line "testing" refers to the human act of re-energizing a line without completing a physical field patrol or observation of a line.

[19] Distribution line "non-reclosing" refers to the deactivation of automatic re-energization of a distribution line or use of a non-reclosing device such as a fuse.

U.S. Forest Service, or other fire-fighting managers) in response to existing/encroaching wildfire threatening to burn into such facilities.

- Automated de-energization of electric transmission and/or distribution facilities due to smoke/fire from an existing fire causing a fault on the line.

Idaho Power will continue its current de-energization practices in the above referenced, and comparable situations. Such outage situations are not defined as PSPS events in the context used here and, as a result, would not trigger PSPS protocols.

7.5.2. PSPS Plan

Idaho Power developed a PSPS Plan (see Appendix B) that operates in parallel with its wildfire mitigation strategy. Although the wind patterns in Idaho Power's service area are generally of a much lower sustained velocity and often less predictable (i.e., micro-bursts) than other utilities' service areas where PSPS has most frequently been utilized (i.e., California), the company's PSPS Plan generally follows industry best practices by considering other utilities' PSPS plans and incorporating input from Idaho Power's external consultant, discussed in 3.2 above, which developed the company's WMP risk maps.

8. Mitigation—T&D Programs

8.1. Overview

Idaho Power's wildfire mitigation strategy relies in part on its various asset management programs and vegetation management program to maintain safe and reliable operation of its T&D facilities in reducing wildfire risk.

8.2. T&D Asset Management Programs

In addition to maintaining a number of existing and newly implemented robust asset management programs intended to reduce wildfire risk, Idaho Power continues to research, monitor, and pilot emerging technologies and strategies to manage its T&D infrastructure.

Idaho Power's key asset management programs supporting wildfire prevention and mitigation are summarized in the table below.

Table 7
Summarized T&D asset management programs (associated with the WMP)

Transmission
Transmission Asset Management Programs
Aerial Visual Inspection Program
Ground Visual Inspection Program
Detailed Visual (High Resolution Photography) Inspection Program
Wood Pole Inspection and Treatment Program
Cathodic Protection and Inspection Program
Thermal Imaging (Infra-Red) Inspections
Wood Pole Wildfire Protection Program (enhanced)
Steel Pole (Structures) (enhanced)
Distribution
Distribution Asset Management Programs
Ground Detail Inspection Program (enhanced)
Wood Pole Inspection and Treatment
Wood Pole Fire Protection Program (enhanced)
Line Equipment Inspection Program
Thermal Imaging (Infra-Red) Inspections
Overhead Primary Harden Program
Replace "small conductor" with new 4acsr or larger conductor (new)
Replace or repair damaged conductor
Re-tension loose conductors including "flying taps" and slack spans as required

- Replace wood-stubbed poles with new wood poles (enhanced)
- Replace white and yellow square tagged poles with new wood poles
- Replace wood pins/wood crossarm with new steel pins/fiberglass crossarms
- Replace steel insulator brackets with new steel pins/fiberglass crossarms (new)
- Replace wedge deadends on primary taps with new polymer deadend strain insulators
- Replace aluminum deadend strain insulators with new polymer deadend strain insulators (new)
- Replace porcelain switches with new polymer switches
- Replace hot line clamps
    - Replace aluminum stirrups
    - Install avian cover
    - Relocate arresters
- Install bird/animal guarding
- Update capacitor banks
    - Replace swelling capacitors
    - Replace oil-filled switches with vacuum style
    - Replace porcelain switches with polymer switches
- Install disconnect switches on CSP transformers
    - Install avian cover
- Update down guys
    - Replace/Install down-guy insulators with fiberglass insulators
    - Tighten down guys
- Tighten hardware
- Correct 3rd party pole attachment clearances (report to Joint Use Department)

Idaho Power has a robust and proven inspection and correction strategy and schedule. Current practices will continue in YRZs. Risk quantification and modeling performed shows that RRZs have a higher level of risk from wildfires so, in addition to its current practices, Idaho Power believes it is prudent to add an annual inspection to minimize the likelihood of a wildfire ignition as well as targeted infrared inspections in select RRZs to identify any potential issues that may not be apparent on visual inspection. As part of the ISO 31000 risk management process, Idaho Power plans to evaluate the effectiveness of inspection and correction activities and schedules and further grow in this area as wildfire risk evolves. The following table summarizes inspection work performed and inspection frequency with respect to wildfire risk zones.

Table 8
Summary of asset inspections and schedules by state and zone

	Inspection Interval				
Asset Inspection Type	**Idaho Non-Risk Zone**	**Oregon Non-Risk Zone**	**Idaho YRZ**	**Oregon YRZ**	**Idaho RRZ**
Transmission Defect Inspections					
Visual	Annually	Annually	Annually	Annually	Annually
Detailed	10 Years	10 Years	10 Years	10 Years	10 Years
Groundline (Wood Pole Test and Treat)	10 Years	10 Years	10 Years	10 Years	10 Years
Wildfire Mitigation Patrol	None	None	None	None	Annually
Infrared Patrol	None	None	None	None	Annually
Distribution OH Defect Inspections					
Visual/Detailed	3 Years	2 Years	3 Years	2 Years	3 Years
Groundline (Wood Pole Test and Treat)	10 Years	10 Years	10 Years	10 Years	10 Years
Wildfire Mitigation Patrol	None	None	None	None	Annually
Infrared Inspections	None	None	None	None	Targeted

8.2.1. Transmission Asset Management Programs

Several of Idaho Power's transmission management programs have been in place for decades and include condition-based aerial visual inspections, ground visual inspections, detailed visual (generally using high-resolution photography) inspections, transmission wood pole inspection and treatment, and cathodic protection. Additionally, Idaho Power has used various methods and materials to prevent wildfire from damaging wood structures and now intends to use a fire-resistant mesh wraps installed on structures located in the RRZ and YRZs.

8.2.1.1. Aerial Visual Inspection Program

Annually, Idaho Power uses helicopters to assist Idaho Power qualified personnel in the visual aerial inspection of transmission lines identified as WECC Path Lines. This method of line inspection is now used for transmission lines located in the RRZs. In addition, unmanned aerial vehicles with high-definition cameras are now used in certain situations to inspect facilities on these lines. These inspections allow personnel to look for potential line defects, which, if found, are noted and scheduled for repair.

All noted defects are prioritized as Priority 1, Priority 2, or Priority 3, based on the criteria listed below:

- **Priority 1**: Defects that, depending on the circumstances, require reporting and repair as soon as reasonably possible.
- **Priority 2**: Defects that, depending on the circumstances, generally require reporting and correction within 24 months of identification. The correction of these defects should be scheduled during crews' normal work schedules. Priority 2 defects not assigned a

corrective plan within 24 months will be reviewed by the T&D vegetation and maintenance engineering leader.

- **Priority 3**: Potential issues that may need correction but do not pose a threat to the system and should be monitored. A Priority 3 designation may also be used by Idaho Power personnel for tracking of certain line construction practices.

Corrective action plans for Priority 1 and 2 defects are determined by engineering personnel for each prioritized defect and are scheduled and repaired.

8.2.1.2. Ground Visual Inspection Program

Annually, Idaho Power qualified personnel (i.e., trained in transmission line inspection procedures and experienced in transmission line construction) complete ground visual inspections of all transmission lines. Ground patrols are completed using four-wheel-drive vehicles, all-terrain vehicles, utility terrain vehicles, and/or on foot. These inspections identify potential line defects that are noted and scheduled for repair following the same process as described in 8.2.1.1.

8.2.1.3. Detailed Visual (High-resolution Photography) Inspection Program

In addition to the annual inspections and associated maintenance, Idaho Power also completes detailed visual inspections generally utilizing high resolution photography. This detailed inspection is typically completed using helicopters, unmanned aerial vehicles, and contracted professionals operating high-definition cameras and, if potential line defects are noted, they are scheduled for repair following the same process as described in 8.2.1.1. The detailed inspections are completed on a 10-year cycle in conjunction with the 10-year cycle of wood pole ground line inspection and treatment (see 8.2.1.4).

8.2.1.4. Wood Pole Inspection and Treatment Program

All wood poles are visually inspected, sounded, and bored for defects and decay on a 10-year cycle. The poles are categorized according to the following:

- **Reported**: Any wood pole inspected and found to be installed within 10 years of the manufactured date or last inspection date.
- **Treated**: Any wood pole inspected and found to be installed 11 years or more prior to the inspection date and is determined to be in sound enough condition to warrant treatment.
- **Rejected**: Any wood pole determined to fit the following criteria:
  - Have less than 4 inches of shell at 48 inches above the ground line; and/or
  - Less than 2 inches of shell at 15 inches above the ground line; and/or
  - Less than 2 inches of shell at the ground line; or

- Is deteriorated and does not meet minimum strength criteria; or
- Fails a visual inspection.

Rejected poles are categorized as: reinforceable with steel, non-reinforceable and are to be replaced.

- **Visually Rejected**: Any wood pole that has been damaged (i.e., burned, split, broken, hit by a vehicle, damaged by animals, etc.) above the ground line to such an extent as to warrant rejection and that cannot be further tested to determine priority status.
- **Sounded, Bored, and Treated**: Any wood pole set in concrete, asphalt, or solid rock 11 years or more prior to the inspection date is internally treated. Internal treatment involves fumigating the good wood and flooding the voids with fumigant.

8.2.1.5. Cathodic Protection and Inspection Program

Cathodic protection systems are employed on select steel transmission towers. These systems use either an impressed current corrosion protection system (ICCP) or direct-buried sacrificial magnesium anodes. Included in Idaho Power's tower maintenance plan, every 10 years, structure-to-soil potential testing is performed on select towers with direct-buried anodes. For ICCP systems, rectifiers and ground-beds are tested to ensure they are functioning properly. Based on test results repairs and adjustments are completed. Each year all rectifiers are inspected, and direct current (DC) voltage and DC current readings noted.

8.2.1.6. Thermal Imaging (Infra-red) Inspections

Idaho Power will complete annual inspections of lines and equipment using thermal imaging (infra-red) cameras. This inspection methodology, although not new to Idaho Power, is being expanded to specifically include the RRZs. Compromised electrical connections and overloaded equipment may be identified using thermal imagery. Identified risks will be prioritized and mitigated using the prioritization methodology noted in 8.2.2.1 of this WMP.

8.2.1.7. Wood Pole Wildfire Protection Program

Idaho Power has utilized numerous technologies to minimize the damage to wood poles that have been exposed to wildfires. The current technology of "mesh wraps" is utilized on transmission wood poles located in the RRZs and YRZs.

8.2.1.8. Transmission Steel Poles

Idaho Power will utilize steel poles or structures for new transmission line construction projects built to 138 kV standards and above in an attempt to minimize wildfire damage and improve transmission line resilience. Wood poles may be used on 138 kV structures for emergency and maintenance replacements based on the specific engineering, right-of-way, permitting, and scheduling requirements for each project. Wood construction is used for voltages below 138 kV unless a different material is needed to meet specific engineering or planning requirements.

8.2.2. Distribution Asset Management Programs

Idaho Power has several distribution asset management programs that are mature, have been implemented for decades, and will continue to be utilized in the RRZs. These programs include condition-based, detailed, and ground visual inspection; distribution wood pole inspection and treatment; and line equipment inspection.

Idaho Power also has an enhanced overhead distribution "hardening" program to implement in the RRZs. Examples of specific work include replacement of small conductors and associated hardware and replacement of wooden pins and associated wooden crossarms.

8.2.2.1. Ground Visual Inspection Program

Annually, qualified line patrol personnel (trained in distribution line inspection procedures and experienced in distribution line construction) complete visual wildfire mitigation inspections of the distribution lines located in the RRZs to identify Priority 1 defects and those that may cause an outage or possible ignition. The ground patrols are completed using four-wheel-drive vehicles, all-terrain vehicles, utility terrain vehicles, or on foot. These inspections identify potential line defects that are noted and scheduled for repair. Detailed distribution inspections are completed on a predetermined schedule and may be performed in conjunction with annual visual inspections.

All noted defects are prioritized as Priority 1, Priority 2, or Priority 3, based on the criteria listed below:

- **Priority 1**: Defects that, depending on the circumstances, require reporting and repair as soon as reasonably possible.
- **Priority 2**: Defects that, depending on the circumstances, generally require reporting and correction within 24 months of identification. The correction of these defects should be scheduled during crews' normal work schedules. Priority 2 defects not assigned a corrective plan within 24 months will be reviewed by the T&D Vegetation and maintenance engineering leader.
- **Priority 3**: Potential issues that may need correction but do not pose a threat to the system and should be monitored; or tracking of certain line construction practices.

Corrective action plans for Priority 1 and 2 defects are determined by engineering personnel for each prioritized defect and are scheduled and repaired.

8.2.2.2. Wood Pole Inspection and Treatment Program

All wood poles are visually inspected, sounded, and bored for defects and decay. The procedure is noted in 8.2.1.4.

8.2.2.3. Line Equipment Inspection Program

Line equipment in wildfire risk zones, including capacitor banks, automatic reclosing devices, and regulators, are inspected annually prior to wildfire season by line operations technicians. The inspection includes a visual inspection and, when electronic controls are present, data is retrieved and analyzed for proper operation.

8.2.2.4. Thermal Imaging (Infra-red) Inspections

Idaho Power will complete annual inspections of lines and equipment using thermal imaging (infra-red) cameras. This inspection methodology, although not new to Idaho Power, is being expanded to specifically include the RRZs. Compromised electrical connections and overloaded equipment may be identified using thermal imagery. Identified risks will be prioritized and mitigated using the prioritization methodology noted in 8.2.2.1 of this WMP.

8.2.2.5. Overhead Primary Hardening Program

Overhead distribution infrastructure located in the RRZs will be analyzed and may be inspected and hardened depending upon proximity to fuels conducive to wildfires in the unlikely event of failure of the line infrastructure. It is expected to take multiple years to inspect and harden all applicable overhead distribution lines.

The Overhead Primary Hardening program is intended to upgrade or repair certain overhead distribution infrastructure. Criteria as outlined in Table 7 drives the program work. Notable criteria are further explained in the following sections of this WMP.

8.2.2.5.1. Conductor "Small" Replacement

Idaho Power is implementing replacement of small conductors in the RRZs. Small conductors are those in sizes less than that of 4ACSR conductor. Examples of small wires include 6Cu, 6-3SS, 8A, 8A CW, 9IR, etc. These small conductors will be replaced with standard larger conductors, primarily with 4ACSR conductor.

8.2.2.5.2. Wood Pin and Crossarm Replacement

Wooden crossarms installed with wooden pins will continue to be replaced with fiberglass crossarms and steel pins. This work will be coordinated and included in the overhead primary hardening program. And, whenever work is being completed on a structure that requires replacement of wooden crossarms, Idaho Power will, generally, install fiberglass crossarms.

8.2.2.5.3. Porcelain Switch Replacement

Porcelain switches located in the RRZs will continue to be replaced with polymer switches. Additionally, associated hot clamps and stirrups will be replaced. This work will be coordinated and included in the overhead primary hardening program.

8.2.2.5.4. Fuse Options

Idaho Power investigated reasonable alternatives to replace certain expulsion fuses and expulsion arrestors. A pilot program was initiated in 2020 to replace several expulsion fuses with non-expulsion fuses in the vicinity of the Boise foothills. This pilot program was successful and Idaho Power implemented a subsequent program to replace expulsion fuses with non-expulsion fuses in RRZs as a part of its distribution overhead primary wildfire hardening program.

8.2.2.5.5. Wood Pole Wildfire Protection Program

Idaho Power has utilized numerous technologies to minimize the damage to wood poles that have been exposed to wildfires. The current technology of "mesh wraps" is utilized on certain distribution wood poles located in the RRZs.

8.3. T&D Vegetation Management

Idaho Power's T&D vegetation management program (VMP) addresses public safety and electric reliability and helps to safeguard T&D lines from trees and other vegetation that may cause an outage or damage to facilities. Specifically, the lines are inspected periodically, and trees and vegetation are cleared away from the line while certain trees are removed entirely. In addition, the VMP addresses the clearing of vegetation near the base of certain poles and line structures. The responsibilities of the VMP include the planning, scheduling, and quality control of VMP associated work. The VMP is active year-round and complies with applicable NESC, federal, and state requirements. Additional vegetation monitoring tools are in various stages of development, and Idaho Power will evaluate such tools for potential future implementation.

Idaho Power's key components of its VMP, relative to the WMP, are summarized in the table below.

Table 9
VMP summary

Vegetation Management
Transmission
Pre-Fire Season Inspection and Mitigation
Line Clearing Cycle Goal: 3-year cycle for valley areas & 6-year cycle for mountain areas
Tree Removals - Hazard Trees
Targeted Pole Clearing
100% Quality Assurance/Quality Control Auditing in RRZs and YRZs
Distribution
Pre-Fire Season Inspection and Mitigation
Line Clearing Cycle Goal: 3-year cycle in all areas with mid-cycle pruning occurring in 2nd year in RRZs and YRZs*
Tree Removals - Cycle Busters/Hazard Trees
Targeted Pole Clearing
100% Quality Assurance/Quality Control Auditing in RRZs and YRZs

*Distribution line clearing cycles vary by utility. Idaho Power has set a goal of achieving a 3-year cycle of distribution line clearing.

Vegetation contact with energized powerlines is a cause of outages and potential source of ignition for wildfires. Idaho Power's transition to a sustainable three-year pruning cycle will help reduce wildfire risk across the company's service area. In non-wildfire risk zones, distribution feeders and valley-located transmission lines will be patrolled and pruned on a three-year cycle. A six-year cycle will continue to be employed for transmission lines in mountain locations. Specific to each tree pruned, directional pruning methods will be employed where cuts will meet ANSI A300 standard and adequate clearance will be obtained that should accommodate regrowth without violating the prescribed minimum clearance throughout the cycle.

Reliability data has shown that vegetation contact is one of the most likely sources of faults and possible ignition on the system. As a result, Idaho Power employs the same enhanced vegetation management practices in both YRZs and RRZs despite the different levels of wildfire risk. These practices include mid-cycle patrols and pruning in the second year of the cycle to address "cycle buster" trees and annual "hotspot" patrols to address any new hazard trees or unexpected vegetative growth that poses an immediate threat of contact with energized facilities. In addition, the company strives to complete audits for all pruning work performed in YRZs and RRZs, regardless of reason for the pruning. The audits confirm that pruning cuts meet the specification and proper clearance was obtained. The following table summarizes vegetation management activities with respect to wildfire risk zones.

Table 10
Summary of vegetation management activities and schedules

Vegetation Management	Inspection Interval				
Inspections and Activity Schedule	**Idaho Non-Risk Zone**	**Oregon Non-Risk Zone**	**Idaho YRZ**	**Oregon YRZ**	**Idaho RRZ**
Transmission					
Hazard Tree Patrol	Annually	Annually	Annually	Annually	Annually
Cycle Patrol/Pruning—Valley Locations	3 Years	3 Years	3 Years	3 Years	3 Years
Cycle Patrol/Pruning—Mountain Locations	6 Years	6 Years	6 Years	6 Years	6 Years
Wildfire Mitigation Patrol/Pruning	None	None	None	None	Annually
Cycle Buster Patrol/Pruning	18 Months	18 Months	18 Months	18 Months	18 Months
Distribution					
Wildfire Mitigation Patrol/Pruning	None	None	Annually	Annually	Annually
Cycle Patrol/Pruning	3 Years	3 Years	3 Years	3 Years	3 Years
Mid-Cycle Patrol/Pruning	None	None	2 Years after Cycle Prune	2 Years after Cycle Prune	2 Years after Cycle Prune
Cycle Buster Patrol/Pruning	None	18 Months	None	18 Months	None
Quality Assurance (Transmission and Distribution)					
Post-Pruning Audit Inspections	Sampling	Sampling	100%	100%	100%

8.3.1. Definitions

Applicable Transmission Lines—Each overhead transmission line operated within the WMP RRZ at 46 kilovolts (kV) or higher.

Cycle Buster—Trees that grow at a rapid rate, requiring a more frequent trimming schedule than the normal trim cycle.

Hazard Tree—Any vegetation issue that poses a threat of causing a line outage but has either a low or medium risk of failure in the next month. Hazard trees will be further defined as posing either a medium hazard or low hazard.

High-Priority Tree—Any vegetation condition likely to cause a line outage with a high risk of failure in the next few days or weeks. High-priority trees could also be vegetation that is in good condition but has grown so close to the lines that it could be brought into contact with the line through a combination of conductor sag and/or wind-induced movement in the conductor or the vegetation.

Line Clearing Cycles—T&D clearing of lines defined on a periodic basis.

8.3.2. Transmission Vegetation Management

Maintaining a zone near transmission lines that is free of vegetation has long been a priority for Idaho Power. The clearance zone is voltage-level dependent and defined by federal and state regulations.

8.3.2.1. Transmission Vegetation Inspections

Utility arborists annually conduct aerial and/or ground patrols on each applicable transmission line to identify and mitigate vegetation hazards. In addition, transmission patrol personnel inspect all applicable transmission lines once a year to identify any transmission defects and vegetation hazards. During these inspections, the patrol personnel will identify hazardous vegetation, within or adjacent to the Right of Way (ROW), that could fall in or onto the transmission lines or associated facilities. The patrol personnel will evaluate the hazardous vegetation as to the level of threat posed by categorizing the vegetation as a *high priority*, *medium hazard*, or *low hazard*. Any hazardous vegetation found is reported to the utility arborist and documented. Any hazardous vegetation categorized as a *high priority* and that presents a risk to cause an outage at any moment shall also be reported without any intentional time delay to the grid operator. The utility arborist will conduct a follow-up inspection if potential hazard trees or grow-ins are identified. The utility arborist prioritizes and schedules any remedial action for all reported vegetation issues.

8.3.2.2. Transmission Line Clearing Cycles

Transmission lines will be cleared on long-term cycles based on 3 years for urban and rural valley areas and 6 years for mountain areas. However, shorter clearing cycles may occur if conditions dictate out-of-cycle trimming. In most cases, vegetation is cleared primarily through manual cutting of targeted trees and tall shrubs. However, when appropriate and in compliance and permission with federal and state requirements, tree-growth regulators and spot herbicide treatments are applied as effective techniques for reducing re-growth of sprouting deciduous shrubs and trees and extending maintenance cycles.

8.3.2.3. Transmission Line Clearing Quality Control and Assurance

In non-wildfire risk zones, audits are performed on a random sample of pruning worksites. These audits are performed through a combination of the contracted arborists that planned the work and Idaho Power's utility arborists. Due to the elevated risk of wildfire in YRZs and RRZs, audits will be performed on pruning work performed in YRZs and RRZs regardless of the reason for the patrols and pruning. The audits will be performed by a combination of contracted arborists and Idaho Power's utility arborists to check whether pruning cuts meet specification and proper clearance was achieved.

8.3.3. Distribution Vegetation Management

Idaho Power is actively working to clear distribution lines throughout Idaho Power's service area on a three-year cycle.[20] Additionally, in the RRZs and YRZs, Idaho Power completes annual vegetation line inspections and mid-cycle clearing of the lines in the second year, is increasing the number of trees removed, and is completing 100% quality control reviews of contractor line clearing work by certified arborists.

8.3.3.1. Distribution Line Clearing Cycles

Idaho Power is actively working to clear distribution lines on a three-year cycle. In RRZs and YRZs, Idaho Power's goal is to perform mid-cycle pruning in the second year to remove faster growing vegetation to ensure the lines are clear of vegetation for the full pruning cycle. In addition, Idaho Power clears lines based upon "special request" in the situations that fast growing, unexpected growth occurs and is reported by any employee or customer.

8.3.3.2. Distribution Vegetation Inspections

In addition to regular cycle pruning activities, utility arborists are annually conducting ground patrols to identify potential vegetation hazards of each distribution line identified in the RRZs and YRZs. In addition, distribution patrol personnel also inspect the lines in the RRZs annually. During these inspections, patrol personnel identify infrastructure defects and hazardous vegetation, within or adjacent to the ROWs, that could fall in or onto the distribution lines or associated facilities. The patrol personnel then evaluate the hazardous vegetation as to the level of threat posed by categorizing the vegetation as a *high priority*, *medium hazard*, or *low hazard*. Any hazardous vegetation found is reported to the utility arborist and documented.
Any hazardous vegetation categorized as a *high priority* and that presents a risk to cause an outage at any moment shall also be reported without any intentional time delay to the Grid

[20] Idaho Power will test a three-year cycle for a period of 4 or 5 years to verify that such a cycle can be maintained and that the expected benefits are realized.

Operator. The utility arborist will conduct a follow-up inspection if potential hazard trees or grow-ins are identified. The utility arborist prioritizes and schedules any remedial action for all reported vegetation issues.

8.3.3.3. Distribution Line Clearing Procedures

In most cases, vegetation is cleared as scheduled work and includes, but is not limited to, the removal of dead branches overhanging power lines, weak branch attachments, damaged root base or dead or dying trees leaning toward Idaho Power facilities. Vegetation clearing methods include crews using chain saws or specialized pruning machines. Trees are cleared using a pruning procedure called directional or natural pruning, a method recommended by the International Society of Arboriculture, and the ANSI A300 standards.

However, when appropriate and in compliance and permission with federal and state requirements, tree-growth regulators and spot herbicide treatments are applied as effective techniques for reducing re-growth of sprouting deciduous shrubs and trees and extending maintenance cycles.

Through its vegetation management program, Idaho Power has a target to maintain clearance distance between vegetation and conductors as follows:

- Five feet for conductors energized at 600 through 50,000 volts.
- Clearances may be reduced to three feet if the vegetation is not considered to be readily climbable because the lowest branch is greater than eight feet above ground level.
- New tree growth that is no larger than ½ inch in diameter may intrude into this minimum clearance area provided it does not come closer than six inches to the conductor. This new growth is identified during line patrols and removed.
- For conductors energized below 600 volts, vegetation is pruned to prevent the vegetation from causing unreasonable strain on electric conductors.

8.3.3.4. Distribution Line Clearing Quality Control and Assurance

Similar to the transmission section, in non-wildfire risk zones, audits are performed on a random sample of pruning worksites. These audits are performed through a combination of the contracted arborists that planned the work and Idaho Power's utility arborists. Due to the elevated risk of wildfire in YRZs and RRZs, audits will be performed on pruning work performed in YRZs and RRZs regardless of the reason for the patrols and pruning.

8.3.4. Pole Clearing of Vegetation

Idaho Power has historically cleared vegetation from the base of certain transmission wood poles and a limited number of distribution wood poles in Idaho. These vegetation clearing practices have been deemed an effective method of minimizing wildfire damage to existing wood poles. Where acceptable and permissible, Idaho Power removes or clears vegetation in a 20-foot radius surrounding the wood poles and applies a 10-year weed-control ground sterilant (SpraKil SK-26 Granular). Idaho Power submitted an SF-299 application with the Oregon BLM Vale District Office to prepare an Environmental Assessment to use the same ground sterilant on transmission and distribution facilities in Oregon. BLM staff estimate issuing herbicide permits in mid-2024.

9. Wildfire Response

9.1. Overview

Idaho Power responds to wildfires involving or impacting its facilities and/or resulting in a system outage; depending on the specific circumstances, Idaho Power may also respond to wildfires with the potential to result in an outage. Idaho Power's actions include without limitation:

- Taking appropriate steps, where safe to do so, to protect Idaho Power-owned facilities from fire damage;
- Restoring electrical service following an outages; and,
- Communicating with and informing customers.

These actions are taken on a 24-hour basis.

9.2. Response to Active Wildfires

Idaho Power field crews are trained to respond to active wildfires to monitor the situation regarding Idaho Power's facilities. Although they carry certain fire suppression equipment for use on very small fires in limited situations, Idaho Power's crews are not professionally trained firefighters and are instructed not to place themselves in a hazardous position when responding to wildfires. When responding to an active wildfire, Idaho Power personnel immediately report to, and take appropriate direction from, the Incident Commander (IC) or other fire response entity official with jurisdiction over the incident.

9.3. Emergency Line Patrols

At certain times, unplanned de-energization of lines requires qualified line personnel to conduct "emergency" patrols (inspections) of the de-energized lines. These patrols identify outage causes, damaged facilities, ingress/egress routes, and restoration requirements (number of crews, crew sizes, and necessary materials).

9.4. Restoration of Electrical Service

Idaho Power personnel restore electrical service when it is safe to do so following a wildfire. Trained field crews report to the site where damage has occurred with equipment and new materials and develop a plan to remove and rebuild damaged facilities. Depending on the situation, contracted field crews—such as line crews and vegetation management crews—are also deployed to assist in restoration efforts. Restoration work may take hours or, in some rare cases, days to complete. Depending on the extent of damage, customers may need to perform repairs on their facilities and pass inspections by local agencies prior to having full electric service restored.

Due to the unique construction, need for specialized equipment, and—in many cases—remote location of many of Idaho Power's transmission lines, Idaho Power developed a *Transmission Emergency Response Plan*. This plan includes restoration processes related to all transmission voltage classes from 46 through 500 kV. The plan outlines the basic approach and certain details about notification, materials, damage assessment, coordination, and preparedness.

9.4.1. Mutual Assistance

Idaho Power is a member of the Western Region Mutual Assistance Agreement (WRMAA), of which the majority of western United States electric utilities are also members. Member utilities provide emergency repair and restoration assistance to other member utilities requesting assistance when dealing with damaged electric facilities following a significant wildfire or weather event. In the event of a catastrophic wildfire that causes widespread damage to Idaho Power's system, Idaho Power may request restoration assistance via the WRMAA as a last resort option after utilizing available internal personnel and contracted entities.

9.5. Public Outreach and Communications

In 2022, Idaho Power developed and began following an *Outage Communication Playbook* (Playbook) to guide PSPS and load shed protocols. The Playbook ensures consistent and reliable communication to internal and external stakeholders. External communication includes targeted customers, Public Safety Partners, and operators of critical facilities. The Playbook guides activities and identifies key roles and responsibilities of internal Idaho Power employees. Supplemental information and resources are also included to ensure effective and consistent communication is made prior to, during, and after an event.

10. Communicating About Wildfire

10.1. Objective

Idaho Power communicates information about this WMP, including PSPS, and wildfire issues in general, to employees, customers, government officials, the public and other stakeholders. Topics of these communications vary due to timing and audience. For example, all customers can benefit from outage preparedness tips and information about how we are hardening the grid. We discuss PSPS plans in greater detail with Public Safety Partners and operators of critical facilities, as well as customers who live in PSPS zones.

The following core messages are the foundation for all wildfire-related communications:

- How customers can prepare for wildfire-related outages, including where to find outage and PSPS information and how to sign up for alerts and update contact information
- Ways customers can reduce wildfire risk
- Idaho Power's work to protect the grid from wildfire and reduce wildfire risk

10.2. Community Outreach

10.2.1. Community Engagement

Idaho Power presents and distributes information on its WMP to a wide variety of stakeholders including the BLM, U.S. Forest Service, and county and city officials.

Idaho Power engages with various Public Safety Partners, including local governments, emergency managers, and Idaho and Oregon's ESF-12 and social service and welfare agencies (e.g., Oregon's Department of Human Services). These engagements focus on wildfire awareness, prevention, and outage preparedness. For example, the company worked with the Boise City Fire Department to develop updates to the Boise City Fire Code related to Wildland-Urban interface areas.

Idaho Power meets with all Public Safety Partners at least once a year and more frequently as needed. In counties with active local emergency planning committees, Idaho Power is an engaged member. The company uses a variety of methods to communicate with Public Safety Partners, including personal contact via phone, email, and text. We meet with identified Public Safety Partners annually and document their communication preferences in our outreach database. During an event, this information will be used to contact each partner.

Idaho Power conducted over 20 WMP and PSPS plan presentations in 2022. At each one, stakeholders were asked to provide feedback to inform future versions of the WMP. Notable presentations included:

- Local emergency management planning committee meetings across our service area
- Public meetings in communities with PSPS zones and in all Oregon counties we serve
- Idaho Emergency Preparedness Conference
- Idaho Public Health Planning Conference
- Snake River Fire Chiefs annual meeting held in Oregon
- Idaho VOAD (Volunteer Organizations Active in Disasters) Annual Conference
- Seven public meetings in Ontario, Huntington, and Halfway at the end of fire season to gain feedback from customers and stakeholders to help inform future plans. Similar meetings will be held in Idaho counties prior to the 2023 fire season.

Idaho Power has also conducted functional exercises with Public Safety Partners before wildfire season. These exercises mimic fire emergencies, including PSPS events, to improve all parties' wildfire preparedness. For example, in June 2022, Idaho Power conducted a PSPS mock event in our Idaho service area. Several Public Safety Partners were included in the event to test our communication and coordination protocols. The event was held over a three-day period and assumed PSPS events across several wildfire risk zones. Following the event, participants were asked to provide feedback, which has been incorporated into our plan. Feedback received included:

- Public Health Districts were added as Public Safety Partner contacts. Previously, the Idaho Department of Health and Welfare had planned to communicate to the Public Health Districts in case of a PSPS event. Through the event, we identified that this created a delay in communication to the Public Health Districts.
- Back-up contacts for the Idaho Public Utility Commission were identified in case our primary ESF-12 contact is unavailable.
- The Idaho Office of Emergency Management requested they receive a list of critical facilities that could be impacted by the PSPS event. We added this step to our protocols for Idaho and Oregon.

In addition, Idaho Power participated in two mock events, one conducted by Malheur County and the second with the Idaho Office of Emergency Management's Cascade Rising event. Each event mimicked large power outages. While these were not PSPS-specific, we were able to test and discuss our outage communication protocols. Through those events, two opportunities were identified:

- The Red Cross was added as a Public Safety Partner in Malheur County based on their role in coordinating and supporting CRCs.
- The emPower program was identified as a tool to help notify customers on DMEs if a PSPS event is predicted. Idaho Power is working with the Idaho Department of Health and Welfare, the Independent Living Network, and the Idaho Office of Emergency Management to expand this program to all Idaho counties.

2022 Public Safety Partner Feedback Summary

County emergency managers, the Idaho Office of Emergency Management, the Oregon Office of Emergency Management, and the Idaho Department of Health and Welfare reviewed Idaho Power's WMP plan, PSPS protocols, community outreach strategy and materials, critical facilities, and CRC strategies. Feedback received has been incorporated into our programs. Improvements based on this feedback include:

- Updates to identified critical facilities
- Changes to outreach materials to include county specific information as requested
    - Example: Sign-up information was included for counties with active emergency alert systems
- Revised GIS tools that will be provided to Public Safety Partners if a PSPS event is forecasted

10.2.2. Community Resource Centers

Each county in Idaho Power's service area has unique needs during outage events and requires a customized, flexible approach. During annual meetings with county emergency managers, Idaho Power developed county-specific strategies in preparation for potential large-scale, extended outages. These strategies include working with emergency managers to identify CRC locations to be used, as needed, in a PSPS event. The company formulated strategies for Oregon counties in 2022 and will further explore county strategies for Idaho in 2023. If a PSPS event is forecasted, Idaho Power will strive to work directly with local Public Safety Partners to identify and meet the needs of the local community. Services provided in collaboration with emergency managers could include:

- Stand-up of CRC
- CRC location(s) and logistics included in community outreach/outage notifications

- CRC resources
    - Food, water, and other basic needs
    - Charging stations
    - Auxiliary service coordination such as medical services, housing assistance, family reunification, etc.

10.3. Customer Communications

Safety is one of Idaho Power's core values. It guides our communication strategy for wildfire-related communication to our customers. Communication methods and timing vary based on the audience we are trying to reach and the goal of the communication.

Communication generally falls into two categories: 1) broad outreach to all customers, and 2) targeted outreach to customers in PSPS zones. The company uses a variety of outreach methods to reach a broad customer base with messages about wildfire safety, summer outage preparedness, and grid hardening efforts.

Outreach to customers in PSPS zones was more targeted and frequent. Idaho Power repeatedly urged these customers to update or confirm accurate contact information.

Figure 14
Outreach samples for the 2022 wildfire season

10.3.1. Key Communication Methods

Idaho Power communicates with customers and the public before and throughout wildfire season to inform them of steps the company is taking to reduce wildfire risk and ways they can help prevent wildfires and prepare for outages. Various communication mediums used to accomplish this include:

- *Connections* (This monthly newsletter is an effective way to give customers more in-depth information about the work Idaho Power does, but it is not an effective way to communicate urgent information.)

Figure 15
May 2022 edition of *Connections*

- Videos on topics like vegetation management and PSPS

Figure 16
Idaho Power developed an educational video on how we protect wooden poles from wildfire

- Emails, texts, and phone calls telling customers how to prepare for wildfires, encouraging them to update their contact information, and providing information about grid hardening efforts
    - The company used a new communication tool to notify all customers in PSPS zones by text message, phone call, or email. We mailed letters to customers we couldn't reach with this tool. Every year, the company will work to obtain accurate contact information for all customers in PSPS zones.
- News media (news releases, appearances on broadcast TV and radio shows, interviews, etc.)
- Social media (posts on Facebook, Instagram, and Twitter are an efficient way to reach large numbers of customers and the public in a timely manner). Social media continues to be a critical tool for engaging with customers and communicating wildfire safety. The company's social media campaign for wildfire season focused on three main themes:
    - Wildfire prevention: What Idaho Power is doing and what customers can do to reduce wildfire risk
    - Outage preparation: How customers, especially those who live or have businesses in high-risk areas, should prepare for wildfire-related outages
    - Grid maintenance: How Idaho Power protects the grid, keeping energy safe, reliable and affordable, even during wildfire season.

Figure 17
Sample image of social media post

Social media posts are focused on various aspects of each theme, such as putting out campfires as shown in Figure 18 below; creating defensible spaces around homes and businesses; building a summer outage kit as shown in Figure 17, above; and updating contact information. Posts also include information on installing SPUs on the power distribution system and wrapping wood poles with fire-resistant mesh.

Figure 18
Sample image of social media post

- Postcards and flyers
- Paid advertising (radio, digital, and print advertisements)

- Idaho Power's website (wildfire safety information, such as videos, safety tips, and the latest version of the WMP) can be found at https://www.idahopower.com/outages-safety/wildfire-safety/.

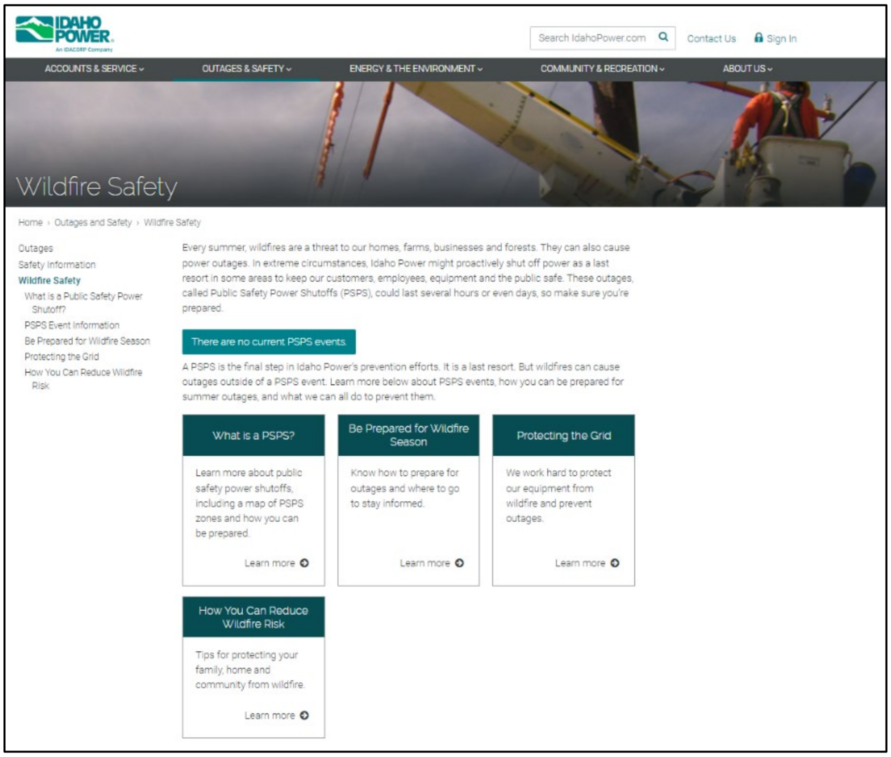


Figure 19
Idaho Power's Wildfire Safety landing webpage

- As shown in Figure 19, on this webpage, the company introduces wildfire and its relationship to delivering power, information on PSPS, and the following links:
  - What is a PSPS?: Explanation of PSPS events, including a map customers can use to determine if their homes or businesses are inside a PSPS zone
  - Be Prepared for Wildfire Season: Preparation tips like building an outage kit and making a plan for feeding livestock, etc.
  - Protecting the Grid: Idaho Power measures to enhance grid resiliency and reduce wildfire risk; an interactive map showing red and yellow risk zones and a link to the WMP
  - How You Can Reduce Wildfire Risk: Tips for preventing wildfires when camping, using fireworks, hauling trailers, etc.
  - PSPS Event Information: Real-time information on active PSPS events, estimated shutoff time, outage duration, and customers impacted

- Public engagement with the company holding at least one public meeting per year in both Oregon and Idaho, offering a virtual meeting with additional access and functionality options. Feedback opportunities are also provided during and after the meetings.

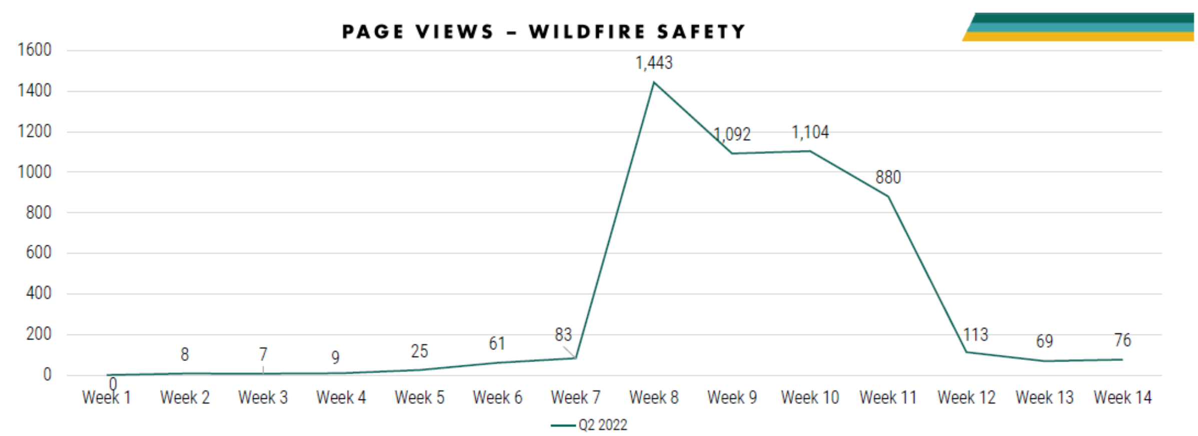
Figure 20
Wildfire mitigation meeting PowerPoint cover slide

10.3.2. Timing of Outreach

The timing of the outreach generally occurs before and during wildfire season. In 2022, Idaho Power originally planned to begin preseason wildfire outreach in early- to mid-April. Due to an unusually wet and cold spring (Boise had accumulating snow on the valley floor on May 9) and a desire to maximize impact, the company delayed release of social media posts, ads, and other communications until the weather changed such that wildfire was more prominently on people's minds. The tone of early communications was meant to encourage customers to think about wildfire season, how they could prepare for it, their role in preventing wildfires, and steps Idaho Power is taking to keep the grid safe and reduce wildfire risk. When the potential for wildfire increased, communications shifted in tone. Messaging put more emphasis on asking customers, especially those in PSPS zones, to update their contact information and prepare for wildfire.

10.3.3. Communication Metrics

Idaho Power uses metrics and monitoring of communication activities to evaluate the effectiveness of our outreach efforts. Idaho Power published a [Wildfire Safety] landing webpage in April 2022 with information on wildfire safety, PSPS, and interactive maps. In the roughly six weeks that followed, before general outreach efforts began, the page saw fewer than 200 hits. However, a campaign of radio, print, and online ads began in earnest in late June and traffic immediately jumped, with 1,443 hits the first week of the campaign as shown in the following graph. Traffic stayed high for about a month before dropping off again.



- This chart shows the Wildfire Safety page for Q2 2022 in green, (4/1/22-6/30/22; 4,970 page views).
- The campaign started during week 8, increasing the traffic drastically. Radio ended on the Sunday of Week 10, and Display ended during Week 11. Spotify ended during Week 14.

Figure 21
Wildfire safety webpage views

The following is a summary of metrics from Idaho Power's 2022 paid communication campaign.

- Radio—Idaho Power's wildfire-safety radio ad campaign ran from May 16 to July 31 in the Idaho Falls, Twin Falls, and Boise markets. The Boise market includes eastern Oregon, reaching as far west as Baker City. The campaign included a total of 4,327 paid and public safety announcement (PSA) match spots; 967 of which were in Spanish and played on Spanish language stations.

- Programmatic Display Ads—Idaho Power's digital display ads appeared on regional websites from May 16 to July 31. These ads resulted in a total of 3,496 clicks in Idaho and Oregon to our wildfire landing webpage, with almost 3.7 million impressions. Almost three-quarters (74.21%) of these impressions occurred via mobile devices.

- 2021 Versus 2022—Idaho Power's 2021 wildfire-safety campaign was comparable to what we deployed in previous years, with the company relying mainly on displays on the Idaho Power website. The 2022 campaign was a much more robust, intricately planned and carefully executed effort. It involved a larger outreach goal and more ads on radio and Spotify that ultimately led to 1.24 million more impressions than the 2021 wildfire-safety campaign.

2022 WMP Communication Summary

Idaho Power used traditional and social media in 2022 to inform customers about the company's WMP, efforts to protect the grid from wildfire, how customers could reduce wildfire risk, how to prepare for wildfire-related outages, and PSPS. Outlets included:

- Newspapers—Print ads and news coverage
- Radio—Paid ads in English and Spanish and news coverage
- TV news coverage
- Printed flyers
- Social media
- Idaho Power website
- Digital display ads
- Postcards—Used to inform customers of the PSPS program and invitations for public meetings
- Spotify—Paid ads
- News Releases—Includes news releases with other Oregon utilities
- Customer email
- Customer newsletters
- Text Messages—Customers in PSPS zones
- Phone Calls—Customers in PSPS zones
- Letters—Customers in PSPS zones

The following updates to the website were made to include new pages focused on wildfire safety in 2022:

- Searchable map of PSPS zones by customer address
- Summer outage preparation
- How Idaho Power protects the grid including mitigation efforts
- How customers can help prevent wildfires
- An active PSPS event page that provides details of active PSPS areas and outage duration information

Additionally:

- Postcards were sent to all customers in PSPS zones to inform them of program details
- Printed 2,600 outage preparedness flyers (English and Spanish) and gave to the Idaho Commission on Aging for delivery with Meals on Wheels
- Wildfire themed customer newsletter (*Connections*) was sent to all customers in May
- Wildfire themed customer email sent to all customers with email addresses on file (approx. 350,000) in May
- Implemented a "pop-up" in the customer My Account web page encouraging customers to update contact information
- Post fire-season postcards were mailed to all Oregon customers in November for invitation to public meetings

10.4. Idaho Power Internal Communications—Employees

Idaho Power communicates with its employees in a variety of ways:

- *News Scans* for all employees

Page 1 • May 2, 2022

NewsScans

PRESIDENT'S AWARD • SAFETY • INTEGRITY • RESPECT • IDAHO POWER

Dave Spillett and Pule Alo Receive President's Awards for Safety

President and CEO Lisa Grow recently presented the President's Award for Safety to two deserving employees in Pocatello — Meter Specialist Pule Alo and Regional Customer Relations Manager Dave Spillett. Here are their stories.

In early February, Pule arrived at a customer's home in American Falls as part of an account call. As he walked up to the door, he thought he heard crying. Listening, he heard a faint voice calling out for help. He went inside and found the customer lying on the floor at the top of the stairs. The woman had fallen, seriously injured her hip and had been lying there for five days.

After reassuring her he would help, Pule went outside, found cell service and called 911. He returned to the customer, covered her with a blanket to keep her warm and gave her water to drink. He even helped gather some of her belongings she wanted to take with her to the hospital.

Reflecting on the event, Pule said, "I am thankful for the training that we have at Idaho Power and that I was able to help her. I assessed the situation, secured the area and called 911."

You made a difference." Lisa told Pule

This past winter, regional employees identified several safety issues at an apartment building that posed hazards to a tenant. The building owner had converted a meter-utility room into an apartment that was now occupied by a single mother and her young child.

Our employees immediately contacted the

The PSPS Plan is Here. What is it?

For the first time in company history, we've developed a Public Safety Power Shutoff (PSPS) plan.

A PSPS is when a company like Idaho Power proactively turns off power to certain areas where wildfire risk is high due to extreme weather conditions. The outage is an effort to protect our customers, communities, employees and equipment from wildfire in windy, dry conditions.

A PSPS is different from a load shed, which is a proactive outage used to protect the grid if customers' need for power is too high due to growth, extreme weather or other factors. It's also different from outages we've used occasionally *after* a wildfire starts to protect firefighters and other crews near our lines.

Figure 22
May 2, 2022, edition of *News Scans*

- Emails
- Leader communications
- GIS-based visual communication of risk zones and affected overhead lines
- Online training for employees influenced by the WMP
- In-person, hands-on, training for certain field employees

11. Performance Monitoring and Metrics

11.1. Wildfire Mitigation Plan Compliance

The Chief Operating Officer (COO) is the designated oversight officer for the Idaho Power WMP. The Vice President of Planning, Engineering and Construction (VP) is responsible for compliance monitoring, necessary training, and annual review of this WMP.

11.2. Internal Audit

Idaho Power's internal audit department, Audit Services, will periodically conduct an independent and objective evaluation of the WMP to assess compliance with policies and procedures and evaluate achievement of the Plan's objectives. Idaho Power's Compliance department will also periodically review Idaho Power's compliance with federal reliability standards regarding vegetation management practices.

11.3. Annual Review

Idaho Power will conduct an annual review of its WMP and incorporate necessary updates prior to wildfire season.

11.4. Wildfire Risk Map

The Wildfire Risk Map was established in 2020 by an external consultant. As noted in Section 2 of this report, the 2020 analysis was based, in part, on population census data from 2010. Idaho Power plans to reconduct risk modeling in 2023 to include 2020 Census data and explore other areas of consequence as described in Section 3.2.1. Idaho Power intends to review our risk modeling approach on an annual basis and perform modeling updates biennially.

11.5. Situational Awareness

Idaho Power will share its FPI regularly and broadly with Idaho Power personnel and contractors during wildfire season to ensure condition-specific operating requirements are met.

11.6. Wildfire Mitigation—Field Personnel Practices

Idaho Power crews and certain personnel are required to follow the *Field Personnel Practices* when working on lines in the RRZs and YRZs during a red FPI. Specific requirements are found in Idaho Power's *Field Personnel Practices* which is consulted by such crews working in these areas.

11.7. Wildfire Mitigation—Operations

Each year in preparation for the fire season, Idaho Power reviews and establishes:

- Temporary operating procedures for transmission lines during the fire season
- An operational strategy for distribution lines during time periods of elevated wildfire risk during the fire season
- Use of PSPS as a tool of last resort to prevent Idaho Power T&D facilities from becoming a wildfire ignition source or contributing to the spread of wildfires

11.8. Wildfire Mitigation—T&D Programs

This section lists metrics used to evaluate Idaho Power's asset management and vegetation management programs. The metrics are based on progress made towards completing mitigation activities, such as quantities of inspected units. Work is identified and prioritized each year and approved by executive management. Idaho Power's goal is to complete 100% of the work plan each year; however, emergencies or other unplanned events can occur and disrupt the annual work plan. All work is completed in accordance with safety and applicable requirements and industry standards.

Table 11
T&D programs metrics

Transmission	
Transmission Asset Management Programs	**Description**
Aerial Visual Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Ground Visual Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Detailed Visual (High Resolution Photography) Inspection Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Wood Pole Inspection and Treatment Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Cathodic Protection and Inspection Program	Perform 10-year structure-to-soil potential testing on select towers with direct-buried anodes. Perform 10-year rectifier and ground-bed testing on ICCP systems. Annually inspect and record DC voltage and current readings of rectifiers. Complete repairs and adjustments.
Wood Pole Wildfire Protection Program	Inspect and install wraps on selected poles.
Distribution	
Distribution Asset Management Programs	**Description**
Wood Pole Inspection and Treatment Program	Perform 10-year cycle patrols and document identified defects according to priority. Complete repairs according to priority definition.
Line Equipment Inspection Program	Complete annual inspections and data analysis and mitigate defects

Ground Detailed Inspection Program	Perform annual patrols and document identified defects according to priority. Complete repairs according to priority definition.
Thermography (Infra-Red) Inspections	Complete inspections of targeted lines and equipment using thermal imaging (infra-red) cameras.
Distribution Infrastructure Hardening Program	Complete annual work plan
Replace "small conductor" with new 4acsr or larger conductor	
Replace or repair damaged conductor	
Re-tension loose conductors including "flying taps" and slack spans as required	
Replace wood-stubbed poles with new wood poles	
Replace white and yellow square tagged poles with new wood poles	
Replace wood pins/wood crossarm with new steel pins/fiberglass crossarms	
Replace steel insulator brackets with new steel pins/fiberglass crossarms	
Replace wedge deadends on primary taps with new polymer deadend strain insulators	
Replace aluminum deadend strain insulators with new polymer deadend strain insulators	
Replace porcelain switches with new polymer switches Replace hot line clamps Replace aluminum stirrups Install avian cover Relocate arresters	
Install bird/animal guarding	
Update capacitor banks Replace swelling capacitors Replace oil-filled switches with vacuum style Replace porcelain switches with polymer switches	
Replace certain expulsion arrestors	
Install disconnect switches on CSP transformers Install avian cover	
Update down guys Replace/Install down-guy insulators with fiberglass insulators Tighten down guys	
Tighten hardware	
Correct 3rd party pole attachment violations (report to Joint Use Department)	
Replace certain expulsion fuses	

Vegetation Management

Transmission	Description
Pre-Fire Season Inspection and Mitigation	Perform annual pre-fire season inspections no later than June 15 of each year and mitigate noted "hot spots"
Line Clearing Cycles: Strive to maintain 3-year cycle for valley areas & 6-year cycle for mountain areas	Complete annual cycle pruning work plan
Tree Removals - Hazard Trees	Remove targeted hazard trees
Targeted Pole Clearing	Complete annually targeted structures
100% QA/QC Audits in RRZs and YRZs	Complete annually QA/QC audits

Distribution	Description
Pre-Fire Season Inspection and Mitigation	Perform annual pre-fire season inspections no later than June 15 of each year in RRZs and YRZs and mitigate noted "hot spots"
Line Clearing Cycle: Strive to maintain 3-year cycle	Complete annual cycle pruning work plan
Mid-Cycle Pruning in RRZs and YRZs	Complete annual mid-cycle pruning work plan in RRZs and YRZs

Tree Removals - Cycle Busters/Hazard Trees	Complete annual cycle pruning work plan
Targeted Pole Clearing	Complete annually targeted structures
100% QA/QC Audits in RRZs and YRZs	Complete annually QA/QC audits

11.9. Long-term Metrics

In 2022, Idaho Power identified new metrics to measure the performance of the WMP and its effectiveness over time. Vegetation management and grid hardening work is expected to reduce outages and improve reliability in wildfire risk zones. A new approach in gauging the effectiveness of the WMP includes tracking reliability data and specific outage counts based on causes or failures that are considered potential drivers of ignition. The following outage causes were established as baseline potential drivers of ignition and will be monitored for each wildfire risk zone:

- Tree/Vegetation Contact
- Equipment Failure
- Loose Hardware
- Corrosion
- Animal Contact

Historical data was analyzed in 2022 in both RRZ and YRZ to establish baseline metrics that will be used to measure performance over time. Potential drivers of ignition in wildfire risk zones through October have decreased by 8% compared to the previous four-year average. This improvement occurred despite being in early stages of wildfire hardening and enhanced vegetation management activities. The use of outage data to gauge overall WMP performance is expected to be a long-term metric and it takes several years to develop trendlines and averages to draw definitive conclusions and a causal relationship to wildfire mitigation activities. In 2023, the company plans to continue to develop long-term benchmarks based on outage counts and cause codes and will refine our approach by expanding the use of data analytics.

Appendix A
The Wildland Fire Preparedness and Prevention Plan.

Wildland Fire Preparedness and Prevention Plan

TABLE OF CONTENTS

1. Plan Overview

A. Intent of Plan

The purpose of this Wildland Fire Preparedness and Prevention Plan (Plan) is to provide guidance to Idaho Power Company (IPC) employees to help prevent the accidental ignition and spread of wildland fires (wildfires) due to employee work activities in locations and under conditions where wildfire risk is heightened. It is expected that all IPC employees be aware of the provisions of this Plan, operate in accordance with the Plan and conduct themselves in a fire-safe manner.

B. Scope of Plan

The scope of this Plan includes tools, equipment, and field behaviors IPC employees incorporate when working in locations and under conditions where wildfire ignition is heightened.

Operations of Transmission and Distribution (T&D) lines facilities, vegetation management, and T&D lines programs that mitigate wildfire risks are <u>not</u> included in this Plan; they are referenced in the separate Wildfire Mitigation Plan.

2. Situational Overview and Applicability

A. Wildfire Season

The provisions of this Plan shall be applicable during wildfire season. Within IPC's service area, wildfire season is defined as the closed fire season of May 10 through October 20 of each year, as established by Idaho State Law, Title 38-115.

Should any local, state, or federal government land management agency (i.e., the BLM, U.S. Forest Service, Oregon Department of Forestry, Idaho Department of Lands, etc.) issue any wildfire related order that extends wildfire season beyond that specified above, then compliance with that agency's order shall govern.

Many variables—such as drought conditions, weather, and fuel moisture—can cause the wildfire season to begin and/or end earlier or later. In summary, flexibility, judgment, attention to current and forecasted field conditions, and attention to governmental agency issued wildfire orders are necessary such that operational practices can be adjusted accordingly.

B. Wildfire Risk Zones

IPC's Wildfire Mitigation Plan includes a Wildfire Risk Map of IPC's service area.
This Wildfire Risk Map may be accessed at the Idaho Power SharePoint site. All lands in the vicinity of IPC facilities are mapped as Red Zone, Yellow Zone or areas of minimal wildfire risk (i.e., not within a Red or Yellow Zone). Red and Yellow Zones are designated as wildfire risk zones (WRZ). The provisions of this Plan shall apply to work activities taking place during wildfire season in these WRZs.

Should any local, state, or federal government land management agency (i.e., BLM, U.S. Forest Service, Oregon Department of Forestry, Idaho Department of Lands, etc.) issue any wildfire related order, then compliance with that agency's order shall govern if their order is more restrictive than that set forth in this Plan.

C. Fire Potential Index

Idaho Power's Atmospheric Science department has developed an FPI rating system that forecasts wildfire potential across IPC's service area. The FPI considers many current and forecasted elements such as meteorological (winds-surface and aloft, temperatures, relative humidity, precipitation, etc.) and fuel state (both live and dead). The FPI is designed and calibrated for IPC's service area; specifically, those areas in proximity to IPC transmission, distribution, and generation facilities.

The FPI consists of a numerical score ranging from 1 (very green, wet fuels with low to no wind and high humidity) to 16 (very brown and dry, both live and dead dry fuels with low humidity and high temperatures). The FPI scores are grouped into the following 3 index levels:

- **Green:** FPI score of 1 through 11
- **Yellow:** FPI score of 12 through 14
- **Red:** FPI score of 15 through 16

During wildfire season, Idaho Power will determine a daily FPI as described in Section 5 of the WMP. This weather forecast and FPI dashboard is contained within IPC geographic information system (GIS) viewers available to all IPC employees.

D. Decision Making for Field Work Activities

Employees working in the field shall be cognizant of current and forecasted weather and field conditions. Awareness of these conditions, and exercising appropriate judgment, is essential when considering whether to undertake work activities when combinations of high temperatures, low humidity, dry fuels, and/or wind are present or forecasted to be present.

The following process steps shall apply to employees and crews contemplating field work during wildfire season:

Planned or Scheduled Work Activities:

1. Fire Potential Indices:

    a) Employees working in the field—NOT working on transmission or primary distribution lines should:

i. Be aware of the current and forecasted weather and the FPI level for the area in which the work will be performed, through the FPI dashboard.

ii. Once the FPI level for the work zone is identified, proceed with work but consider utilizing Prevention—Practices of Field Personnel (see Section 6 of this Plan).

b) Employees working in the field—working on transmission or primary distribution lines should:

i. Be aware of the current and forecasted weather and the FPI level for the area in which the work will be performed.

ii. Once the FPI level for the work zone is identified, proceed as follows for each FPI level:

1. **Green FPI in All Zones:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel (see section 4 of this Plan)

2. **Yellow FPI in All Zones:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel (see section 4 of this plan)

3. Red FPI

a) **In Normal Zone:** Proceed with the work.
Consider utilizing Prevention—Practices of Field Personnel (see Section 6 of this plan)

b) **In Medium Zone:** Proceed with the work. However, it is a requirement to follow the Prevention—Practices of Field Personnel (see Section 6 of this plan)

c) **In High Zone: STOP.** No planned work activities shall take place unless approved by operations level manager. Work consideration will be restoration of electric service or work deemed critical to providing safe, reliable electric service. If work is approved to proceed it is a requirement to follow the Prevention—Practices of Field Personnel (see Section 6 of this plan).

<table>
<tr><td rowspan="3">Fire Potential Index (FPI)</td><td>High</td><td>15 to 16 (Red)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

REQUIRED</td><td>STOP/NO WORK</td></tr>
<tr><td>Elevated</td><td>12 to 14 (Yellow)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td></tr>
<tr><td>Normal</td><td>1 to 11 (Green)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td><td>Proceed with work

Utilize Prevention/ Practices of Field Personnel

(Optional)</td></tr>
<tr><td></td><td></td><td></td><td>None</td><td>Yellow (Tier 2)</td><td>Red (Tier 3)</td></tr>
</table>

2. Land Management Agency Restrictions: Follow the requirements and restrictions of any wildfire restrictions related order that is issued by local, state, or federal land management agencies.

    a) Immediately upon receiving knowledge of an order, The Environmental Services department will notify, via email, operations leadership within Power Supply, Customer Operations and Business Development, and T&D Engineering and Construction of wildfire related requirements and restrictions orders that are issued by local, state, or federal land management agencies.

Emergency Response and Outage Restoration Work Activities:

Follow the same steps as identified above for planned work activities. However, it is recognized that the nature of emergency response and outage restoration situations will often require exceptions to the above. In these situations, leadership should be consulted, and appropriate judgment should be used given the nature of the emergency or outage at hand.

3. Preparedness—Tools and Equipment

A. Required Personal Protective Equipment

Standard IPC Personal Protective Equipment (PPE) shall be worn in accordance with the IPC Safety Standard.

When entering a designated fire area being managed by the BLM or the U.S. Forest Service, additional PPE requirements may be in force by those agencies. These typically include:

- Hardhat with chinstrap
- Long sleeve flame-resistant (FR) shirt and FR pants
- Leather gloves
- Exterior leather work boots, 8” high, lace-type with Vibram type soles
- Fire shelter

B. Required Tools and Equipment

Employees NOT working on transmission or distribution lines: Standard tools and equipment in accordance with the IPC Safety Standard and Fleet Services.

Employees working on transmission or distribution lines: IPC and the State of Idaho BLM entered into a March 2019 Master Agreement that governs various IPC and BLM interactions, including wildfire prevention related provisions. In addition to State of Idaho BLM lands, IPC has elected to apply these requirements to all work activities taking place on all WRZ in Idaho, Nevada, Montana, and Oregon. These requirements include:

- During the wildfire season (May 10–October 20) or during any other wildfire season ordered by a local, state, or federal jurisdiction, IPC, including those working on IPC’s behalf, will equip at least 1 on-site vehicle with firefighting equipment, including, but not limited to:

    a) Fire suppression hand tools (i.e. shovels, rakes, Pulaski’s, etc.),
    b) a 16-20-pound fire extinguisher,
    c) a supply of water, sufficient for initial attack, with a mechanism to effectively spray the water (i.e. backpack pumps, water sprayer, etc.). This requirement to carry water is dependent on the vehicle type and weight restrictions. For example, a mini-excavator would not be required to carry water since there is no safe way to do so, or a loaded bucket truck may not be required to carry water because of weight limitations.

- At a minimum, equip each truck that will be driven in the WRZs during wildfire season with at least:
    a) One round, pointed shovel at least 8-inches wide, with a handle at least 26 inches long
    b) One axe or Pulaski with a 26-inch handle or longer
    c) A combination of shovels, axes, or Pulaskis available to each person on the crew

d) One fire extinguisher rated no less than 2A:10BV (5 pounds)
e) 30-200 gallons of water in a fire pumper and 5-gallon back packs

IPC personnel will be trained to use the above tools and equipment to aid in extinguishing a fire ignition before it gets out of control and take action that a prudent person would take to control the fire ignition while still accounting for their own personal safety.

C. Land Management Agency Restrictions and Waivers

The Environmental Services department will notify operations leadership within Power Supply, Customer Operations and Business Development, and T&D Engineering and Construction of any wildfire related requirements and restrictions orders that are issued by local, state, or federal land management agencies. Typical orders issued each fire season include:

- BLM. During BLM's Stage II Fire Restrictions, IPC's Environmental Services department will obtain an appropriate waiver. Field personnel shall take appropriate precautions when conducting work activities that involve an internal combustion engine, involve generating a flame, involve driving over or parking on dry grass, involve the possibility of dropping a line to the ground, or involve explosives. Precautions include a Fire Prevention Watch Person who will remain in the area for 1 hour following the cessation of that activity. Also, IPC personnel will not smoke unless within an enclosed vehicle, building, or designated recreation site or while stopped in an area at least 3 feet in diameter that is barren or cleared of all flammable materials. All smoking materials will be removed from work sites. No smoking materials are to be discarded.
- State of Oregon Department of Forestry (ODF). Prior to each summer fire season, the ODF issues a "Fire Season Requirements" document that specifies required tools, equipment, and work practices. In addition to State of Oregon lands, IPC has elected to apply these requirements to all work activities taking place on all WRZ, BLM lands, and Forest Service lands within the State of Oregon. Go to https://www.oregon.gov/ODF/Fire/Pages/Restrictions.aspx for ODF's Fire Season Requirements order.

- Other sites for reference that contain fire restriction orders include:
    - Oregon— Blue Mountain Interagency Fire Center at http://bmidc.org/index.shtml
    - Nevada—Fire Information at https://www.nevadafireinfo.org/restrictions-and-closures
    - Montana—https://firerestrictions.us/mt/

4. Prevention—Practices of Field Personnel

A. General Employee Practices

The below listing includes, but is not limited to, practices and behaviors employees shall incorporate depending on the FPI and level of WRZs during fire season.

1. Daily tailboards must include discussion around fire mitigation planning. Discussion topics include, but are not limited to:
   a. Items 2 through 7 below
   b. Water suppression
   c. Hand tools
   d. Welding blankets
   e. Mowing high brush areas (weed wacker)
   f. Watering down the worksite before setting up equipment

2. Weather conditions and terrain to be worked shall be considered and evaluated. Items to be considered include, but are not limited to:
   a. Identify the FPI for the area being worked (see Section 3.2.2)
   b. Monitor weather forecasts and wind and humidity conditions
   c. Identify surroundings. i.e., wildland-urban interface, BLM lands, Forest Service lands, proximity to any homes and structures, etc.
   d. Identify local fire departments and locations
   e. Evaluate the terrain you are working in (steep or flat)
   f. Consider whether the work will occur during the day or at night

3. Work procedures and tools that have potential to cause a spark or flash shall be considered and evaluated. Items to be considered include, but are not limited to:
   a. Performing energized work
   b. Grinding or welding
   c. Trees contacting electrical conductors
   d. Hot saws
   e. Chainsaws
   f. Weed wackers
   g. Sawzalls

4. Monitoring the worksite throughout the project.
   It is imperative that all crews and equipment working in the WRZs areas are continuously monitoring and thoroughly inspecting the worksite throughout the project. This includes prior to leaving the work area for the night or before moving on to the next structure.

5. Employee cooking stoves.
   When working in remote locations, often employees bring food that needs to be cooked. Open flames should not be allowed. Cook stoves may be permitted by leadership but special precautions must be followed to use:
   a. The stove or grill must be in good repair and of sturdy construction
   b. Stoves must be kept clean, grease build up is not allowed
   c. Fueling of the stove must follow the fueling procedures when liquid fuels are used
   d. Cooking must be in areas free of combustible materials

6. Smoking on the job site.
   Carelessly discarded smoking materials can result in wildfire ignition. The following practices shall be followed:
   a. Do not discard any tobacco products from a moving vehicle.
   b. Smoking while standing in or walking through forests or other outdoor areas when IPC's FPI rating is above a Green level is prohibited.
   c. All employees must smoke **only in designated areas** and smoking materials must be disposed of in half filled water bottles or coffee containers half filled with sand. Smoking materials shall not be discarded on any site.

7. Post job site inspection.
   Final inspection or post-checking the work site for any ignition hazards that may remain is essential to the proper completion of the work and true mitigation of the hazards. Post-checking the work will help ensure the hazards were mitigated and provide a final chance to see if any new hazards or hot spots exist before leaving the work site.

B. Behaviors Relating to Vehicles and Combustion Engine Power Tools

It is important to consider work procedures, equipment conditions, employee actions, potential causes, and other sources that could lead to fire ignition. Some work practices may be performed on roadways that have little to no risk of fire ignition. Leadership should consider scheduling off-road equipment use during times of green fire risk. Employees should also consider alternative tools, work methods or enhanced suppression tools to reduce the risk or spread of fire.

1. Additional heat may bring vegetative materials to an easier point of ignition.
   This includes, but is not limited to, the following vehicles:
   a. Pickups, crew cabs, line-beds, buckets trucks (large and small), backhoes, excavators and rope trucks, and any other motorized equipment.

2. Vehicle Procedures:
   a. Inspect all engine exhaust, spark arresters and electrical systems of vehicles used off road, daily for debris, holes or exposed hot components and to ensure that heat shields and protective components are in place.
   b. Conduct inspections of the vehicle undercarriage before entering or exiting the project area to clear vegetation that may have accumulated near the vehicle's exhaust system.
   c. Vehicles shall be parked overnight in areas free from flammable vegetation at a minimum distance of 10 feet.
   d. Vehicles and equipment will not be stationary or in use in areas where grass, weeds or other flammable vegetation will be in contact with the exhaust system.
   e. If there is no other workable option for the location that doesn't include weeds, grass or other flammable vegetation, the vegetation and debris will need to be removed.

  f. Consider using a fire-resistant material such as a welding blanket to cover flammable material to act as a heat shield; fire blankets may be a suitable option to avoid removal of vegetation.

3. Hot brakes on vehicles and equipment:
   a. Park vehicles in areas free of combustible materials.
   b. Hot brake emergency parking, during times of yellow or red FPI shall be cleared of combustible materials for a distance of at least 10 feet from the heat source.

4. Fueling procedures:
   a. Tools or equipment should NOT be fueled while running.
   b. Cool down period must be given to allow equipment time to no longer be considered a fire risk.
   c. Allow for a ten-foot radius from all ignition sources.
   d. Any combustible debris should be cleared from the immediate area.
   e. Never smoke while fueling.
   f. Designate fueling areas for all gas-powered tools.

5. Combustion engine power tools:
   Poorly maintained or missing spark arrester screens may allow sparks to escape and cause ignition of vegetation. Ensure proper spark arrester screens are in place for the following tools:
   a. Generators
   b. Pony motors
   c. Pumps
   d. Chain saws
   e. Hot saws
   f. Weed eaters
   g. Brush hog

   Inspect spark arresters daily; clean or replace when clogged, damaged or missing or remove from service until repaired.

5. Reporting

A. Fire Ignition

All fire ignitions shall be immediately reported to regional or system dispatch. Dispatch will notify local fire authorities. All work shall immediately stop and necessary steps taken to extinguish the fire with available tools, water, and equipment. If the fire gets too large to safely contain or extinguish, ensure all employees are accounted for and get to a safe location.

B. Fire Reporting

When reporting a fire ignition to regional or system dispatch provide the following information:

1. Your name
2. Location-reference points including an address, road or street name, cross streets, mountain range, GPS coordinates, as applicable
3. Fire information
4. Size and behavior of the fire
5. Weather conditions

6. Training

Each employee who performs work in wildland fire designated zones shall be trained on the content of this document and be required to complete annual refresher courses through the Workday system. Employees are required to complete fire extinguisher and fire shelter training annually as part of the lineman safety compliance. Documentation of all training shall be retained in Workday.

7. Roles and Responsibilities

Employee	1. Be familiar with the requirements specified in this Plan and operate in accordance with this Plan. 2. Be aware of daily weather forecast and FPI level. 3. Be aware of whether field work will be performed in a WMZ.
Crew Foreman and Front-Line Leaders	1. Establish expectations to direct report employees they are to be familiar with, and follow, Plan requirements. 2. Ensure the crew or team conducts field operations in accordance with this Plan. 3. Be aware of daily weather forecast and FPI level (by viewing the FPI dashboard or by calling into dispatch or a leader): a) Ensure employees are aware of the FPI level. b) Ensure work practices comply with this Wildland Fire Preparedness and Prevention Plan when the FPI is “Red” and the WMZ is Yellow. c) Ensure no work takes place when FPI is “Red” and the WMZ is Red. Any exceptions to be discussed with manager. 4. Ensure annual training of employees is completed prior to wildfire season. 5. Ensure required tools and equipment are in place prior to wildfire season.
Manager (Regional Operations Manager, Area Manager, T&D Construction Manager)	1. Establish expectations to Crew Foremen and Front-Line Leaders they are to operate in accordance with Plan requirements. 2. Support Crew Foremen and Front-Line Leaders in scheduling training and making required tools and equipment available. 3. View daily weather forecast and FPI dashboard: a) Authorize any exceptions to working when FPI is “Red” and the WRZ is Red. b) Ensure specified audits are timely completed.
Meteorology Department	1. Provide daily weather forecast and update the FPI dashboard contained within the IPC Enviro Viewer.
Environmental Services Department	1. Monitor local, state, and federal land management agencies for any wildfire restriction orders that are issued. 2. Communicate content of any orders issues to Power Supply, COBD, and PEC operations leadership.
Operations Procurement Department	1. Ensure contractors have a copy of this Plan and that contractual requirements are in place to ensure adherence to the Plan.
Vice-President of Planning, Engineering and Construction (VP of PEC)	1. Ensure annual review/update of this Plan is conducted following the completion of each wildfire season.

8. Audit

Prior to the start of wildfire season (May 10), all vehicles associated with work on transmission and distribution lines will be audited by leadership to ensure that those working in WRZs are properly equipped with firefighting equipment. The following checklist must be completed, dated, and signed by a member of leadership (front-line supervisor or above) and kept with the crew or individual until fire season has ended (Oct 20). A copy of each audit checklist shall be sent to the respective manager and senior manager.

Wildland Fire Preparedness Audit Checklist:

Inspector: ____

Signature: ____

Date: ____

Crew: ____

Crew:

At least 1 vehicle will be equipped with the following:

- Fire suppression hand tools (shovels, Pulaski, axes, etc.) for each member of the crew
- A 16–20-pound fire extinguisher (2-10-pound fire extinguishers)
- A supply of water, sufficient for initial attack, with an effective spraying mechanism (i.e., backpack pumps, water sprayer, etc.)
- 30–75-gallon mechanical fire pumper

Individual Truck:

- One round, pointed shovel at least 8-inches wide, with a handle at least 26 inches long
- One axe or Pulaski with a 26-inch handle or longer
- A combination of shovels, axes, or Pulaskis to each person on the crew
- One fire extinguisher rated no less than 2A:10BV (5 pounds)
- 30-200 gallons of water in a fire pumper and 5-gallon back packs

Personal protective equipment (PPE) IPC and BLM standards: Each employee will be required to have the following PPE:

- Hard hat with a chin strap
- Safety glasses
- Hearing protection
- Long sleeve FR shirt FR pants
- Leather gloves
- Exterior leather work boots 8″ high lace type with Vibram type soles
- Fire shelter

Appendix B
The Public Safety Power Shutoff (PSPS) Plan.

Idaho Power Company's Wildfire Public Safety Power Shutoff Plan

December 2021

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1. INTRODUCTION

Wildfires in the Pacific west have increased in their intensity in recent years. In an effort to keep Idaho Power's customers and the communities it serves safe and continue improving the resiliency of Idaho Power's transmission and distribution facilities, Idaho Power implemented a Wildfire Mitigation Plan in 2021, focused on situational awareness, field personnel safety practices and operational wildfire mitigation strategies to prevent the accidental ignition of wildfires. As part of its operational mitigation practices, Idaho Power has developed this Public Safety Power Shutoff Plan (PSPS Plan or Plan) to proactively de-energize electrical facilities in identified areas of extreme wildfire risk to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. This Plan identifies the relevant considerations, process flow and implementation protocol before, during and after a PSPS event. The Plan will be active during wildfire season and reviewed annually and updated as necessary prior to the start of the next wildfire season.

This Plan identifies PSPS implementation considerations and responsibilities for different Idaho Power departments before, during and after PSPS events. Table 2 describes the different phases Idaho Power will use during PSPS events and Figure 7 depicts the communication audiences and timeline Idaho Power will ideally follow during an event. Finally, this Plan describes activities Idaho Power will undertake to prepare and improve the Plan over time, including interactions with local emergency agencies, and briefly describes the financial administration of the Plan.

2. List of Acronyms

AAR—After Action Review

BLM—Bureau of Land Management

COO—Chief Operations Officer

ECMWF—European Centre for Medium-Range Forecasts

EMT—Emergency Management Team

ERC—Energy Release Component

F100—100-Hour Fuel Moisture

FPI—Wildfire Mitigation Plan Fire Potential Index

FWW—Fire Weather Watch

GBCC—Great Basin Coordination Center

GIS—Geographic Information System

IPUC—Idaho Public Utility Commission

IRWIN—Integrated Reporting of Wildland-Fire Information

LSO—Load Serving Operations

NIFC—National Interagency Fire Center

NOAA—National Oceanic and Atmospheric Administration

NWS—National Weather Service

OPUC—Oregon Public Utility Commission

PEC—Planning, Engineering and Construction

PSPS—Public Safety Power Shutoff

RFW—National Weather Service issued Red Flag Warning

SGM—Smart Grid Meter

SME—Subject Matter Expert

T&D—Transmission & Distribution

TDER—Transmission & Distribution Engineering and Reliability

UKMET—United Kingdom Meteorological Office

WMP—Wildfire Mitigation Plan

WRF—Weather Research and Forecasting

3. Definitions

(1) Critical Facilities—Refers to the facilities identified by Idaho Power that, because of their function or importance, have the potential to threaten life safety or disrupt essential socioeconomic activities if their services are interrupted.

(2) ESF-12—Refers to Emergency Support Function-12 and is the Idaho Power Company liaison from the State Office of Emergency Management for energy utilities issues during an emergency for both Idaho and Oregon.[1]

(3) Exercise—Refers to planned activities and assessments that ensure continuity of operations, provide and direct resources and capabilities and gather lessons-learned to develop core capabilities needed to respond to incidents.

(4) Community—Refers to a group of people that share goals, values and institutions.[2]

(5) Local Emergency Manager—Refers to a jurisdiction's role that oversees the day-to-day emergency management programs and activities.[3]

(6) Public Safety Partners—As defined by Idaho Power refers to ESF-12, Local Emergency Management and Idaho's and Oregon's Department of Human Services (or equivalent).

(7) Public Safety Power Shutoff or PSPS—A proactive de-energization of a portion of an Electric Utility's electrical network, based on the forecasting of and measurement of extreme wildfire weather conditions.

[1] Federal Emergency Management Institute (FEMA) National Response Framework (NRF) Emergency Support Functions (ESF) National Response Framework | FEMA.gov.

[2] FEMA definition under "Communities" (pg. 26) National Response Framework (fema.gov).

[3] FEMA definition under "Local Government" (pg. 29) National Response Framework (fema.gov).

4. PUBLIC SAFETY POWER SHUTOFF OVERVIEW

In recent years, the western United States (U.S.) has experienced an increase in the intensity of wildland fires (wildfires). A variety of factors have contributed in varying degrees to this trend, including climate change, increased human encroachment in wildland areas, historical land management practices and changes in wildland and forest health. Recent events in western states have increased awareness of electric utilities' role in wildfire prevention and mitigation.

In an effort to keep Idaho Power's customers and the communities it serves safe and continue improving the resiliency of Idaho Power's transmission and distribution (T&D) facilities, Idaho Power implemented a Wildfire Mitigation Plan (WMP) in 2021 focused on situational awareness, field personnel safety practices and operational wildfire mitigation strategies. As part of its operational mitigation practices, Idaho Power developed this Wildfire Public Safety Power Shutoff Plan (PSPS Plan or Plan) to proactively de-energize electrical facilities in identified areas of extreme wildfire risk to reduce the potential of those electrical facilities becoming a wildfire ignition source or contributing to the spread of wildfires. Based on the inherently disruptive nature of power outages, Public Safety Power Shutoff (PSPS) events must be carefully evaluated under this Plan to balance wildfire risk with potential PSPS impacts on Idaho Power customers and the communities it serves.

The unpredictable nature of wildfire and weather patterns create significant challenges with forecasting PSPS events. Real-time evaluations and decision-making are therefore critical in making PSPS determinations and, depending on the associated wildfire risk, those determinations may result in proactive de-energization in areas not originally anticipated.

5. SCOPE

This PSPS Plan identifies the relevant considerations, process flow and implementation protocol before, during and after a PSPS event. The Plan will be active during wildfire season and reviewed and updated annually as necessary prior to the start of the next wildfire season. Wildfire season (also known as "closed season") is defined by Idaho Code § 38-115 as extending from May 10 through October 20 each year, or as otherwise extended by the Director of the Idaho Bureau of Land Management (BLM). Oregon's wildfire season generally aligns with Idaho's wildfire season and is designated by the State Forester each year pursuant to Oregon Revised Statute 477.505.

6. KEY TENETS

- Advancing the safety of Idaho Power employees, customers and the general public
- Collaborating with key external stakeholders (agencies, counties, local governments, public safety partners, first responders)

- Minimizing both potential wildfire risk and power outage impacts on communities and customers
- Maintaining reliable electric service

7. Wildfire Zones

Idaho Power's WMP identifies areas of heightened wildfire risk within its service territory reflected by the following risk zones:

- Tier 2 Yellow Risk Zones are deemed increased risk areas.
- Tier 3 Red Risk Zones are deemed higher risk areas.

In its WMP, Idaho Power identifies operational practices specific to these zones of heightened wildfire risk for purposes of (1) reducing potential wildfire risk associated with Idaho Power's T&D facilities and field operations, and (2) improving the resiliency of the Idaho Power's T&D system impacted by wildfire. This PSPS Plan sets forth Idaho Power's PSPS evaluation criteria and processes, including operational and communication protocol, for implementing a PSPS.

8. PSPS Implementation Considerations

Idaho Power will initiate a PSPS if the company determines a combination of critical conditions indicate the T&D system at certain locations is at an extreme risk of being an ignition source and wildfire conditions are severe enough for the rapid growth and spread of wildfire. Idaho Power will evaluate as a whole (not relying on one single factor but a combination of all factors), without limitation, the criteria set forth in 9.1–9.17 below.

8.1. Fire Potential Index

In addition to the Risk Zone designations in its WMP, Idaho Power developed a Fire Potential Index (FPI) to forecast wildfire potential across Idaho Power's service area. The FPI converts data on weather; prevalence of fuel (shrubs, trees, grasses); and topography into a numerical FPI score to forecast the short-term wildfire threat in geographical areas throughout Idaho Power's service area. FPI scores range from 1 (very green, wet fuels with low to no wind and high humidity) to 16 (very brown and dry, both live and dead dry fuels with low humidity and high temperatures). FPI scores are grouped into the following 3 index levels:

1) Green—lower fire potential: FPI score of 1 through 11
2) Yellow—elevated fire potential: FPI score of 12 through 14
3) Red—highest fire potential: FPI score of 15 and 16

The FPI supports operational decision-making to reduce potential wildfire risk. During wildfire season, Idaho Power will determine a daily FPI as described in Section 5.2 of the WMP. The FPI forecast is broken into four 6-hour time periods throughout each seven-day forecast. FPI information is provided via email, certain Geographic Information System (GIS) viewers and an FPI dashboard accessible to both Idaho Power employees and contractors from Idaho Power's website. The WMP details operational mitigation efforts in Red Risk Zones when the FPI score in that Red Risk Zone is also Red, including stopping planned work and changing distribution protection operations. A Red FPI score will be a consideration in Idaho Power's determination of whether to initiate a PSPS.

8.2. National Weather Service Red Flag Warning

A Red Flag Warning (RFW) is a forecast warning issued by the National Weather Service (NWS) to inform the public, firefighters and land management agencies that conditions are ideal for wildland fire combustion and rapid spread. RFWs are often preceded by a Fire Weather Watch (FWW), which indicates weather conditions that could occur in the next 12–72 hours. The NWS has developed different zones across the nation for providing weather alerts (such as RFWs) to more discrete areas. These zones are shown on this NWS webpage: Fire Weather. RFWs for Idaho Power's service territory include Idaho Zones (IDZ) 401, 402, 403, 413, 420 and 422; and Oregon Zones (OR) 636, 637, 642, 634, 644, 645 and 646; and are monitored and are factored into Idaho Power's determination of whether to initiate a PSPS. Boise and Pocatello NWS offices will not issue RFWs if fuels are moist and fire risk is low. The following thresholds are used by most NWS offices:

- Daytime:
    - Relative humidity of 25% or less
    - Sustained winds greater than or equal to 10 miles per hour (mph) with gusts greater than or equal to 20 mph over a four-hour time period
- Nighttime:
    - Relative humidity of 35% or less
    - Sustained winds greater than or equal to 15 mph with gusts greater than or equal to 25 mph over a three-hour time period
- Lightning:
    - The NWS rarely issues RFWs for lightning in the western United States. For this to occur, the Lightning Activity Level—a measure of lightning potential specifically as it relates to wildfire risk—needs to be at 3 or higher.

8.3. NWS Fire Weather Forecasts

The NWS provides detailed forecasts for the different weather zones with an emphasis on fire weather indicators (wind speed, relative humidity, lightning potential). A discussion summarizing the weather patterns and highlighting fire threats is included in their extended forecast.

8.4. Publicly Available Weather Models

Idaho Power's Atmospheric Science department uses the following weather models to predict weather timing, duration and intensity:

- Pivotal Weather Link (pivotalweather.com/model.php): Provides numerical weather data, including a NWS blend of models, European Centre for Medium-Range Weather Forecasts (ECMWF), United Kingdom Meteorological Office weather service information and GOES-16 satellite information.

- Graphical Weather Link (graphical.weather.gov/sectors/conusFireWeek.php): A NWS website providing weather, water and climate data, forecasts and warnings for the United States for the protection of life and property. The Fire Weather page provides a daily and weekly view of multiple weather and environmental conditions influencing wildfire activity.

8.5. Idaho Power Weather Model

Idaho Power maintains its own Weather Research and Forecasting (WRF) model using high-resolution data from Idaho Power's weather stations across its service area. This model, along with publicly available weather models, helps develop weather forecasts that include timing, duration and intensity of weather systems. An Idaho regional WRF low-resolution map view is available to the public at atmo.boisestate.edu/view/.

8.6. Storm Prediction Center Fire Weather Outlooks

The Storm Prediction Center's Fire Weather Outlook provides a current, one-day-ahead and three- to eight-day forecast for wildfires over the contiguous United States. This forecast takes into account pre-existing fuel conditions combined with predicted weather conditions that result in a significant risk of wildfire ignition or spread.

8.7. Current Weather Observations

Identifying real-time wildfire weather and associated risks requires predicting conditions that could trigger a PSPS based on observing current weather conditions. Resources available for observing current weather conditions include direct, real-time data from Idaho Power's network of weather stations, available real-time wind speed information from Idaho Power's network of Smart Grid Meters (SGM), as well as Windy: Wind Map and Weather Forecast and the National Weather Service National Oceanic and Atmospheric Administration's (NOAA) Weather and Hazards Viewer.

8.8. National Significant Wildland Fire Potential Forecast Outlook

The National Significant Wildland Fire Potential Forecast Outlook provides wildland fire expectations for the current month, the following month and a seasonal look at the two months beyond that. The main objective of this tool is to provide information to fire management decisionmakers for proactive wildland fire management, reducing firefighting costs and improving firefighting efficiency.

8.9. Great Basin Coordination Center Morning Briefing

The Great Basin Coordination Center (GBCC) is the focal point for coordinating the mobilization of resources for wildland fire and other incidents throughout the Great Basin Geographic Area, which encompasses Utah, Nevada, Idaho south of the Salmon River, the western Wyoming mountains and the Arizona Strip. The GBCC hosts a morning briefing (around 10 a.m. most mornings) that provides situational awareness for Idaho Power's service area.

8.10. GBCC Current and Predicted ERC and F100

The GBCC as described above also provides day-ahead Energy Release Component (ERC), 100-Hour Fuel Moisture (F100) and other fuels conditions information that helps Idaho Power understand wildfire potential in the service area.

8.11. Agency Input

Idaho Power works with Boise NWS Fire Forecasters through daily briefings and NIFC Predictive Service Forecasters on an as-needed basis, generally regarding data clarification, to streamline the transfer of data, information and communications about wildland fire critical to Idaho Power's service area.

Idaho Power works with other agencies, including the U.S. BLM and U.S. Forest Service, as wildland fires approach and impact Idaho Power T&D facilities.

8.12. De-Energization Windspeed Considerations

Idaho Power's service area covers 24,000 square miles across southern Idaho and eastern Oregon. The environmental factors across this area vary drastically from high desert landscape to mountainous terrain. Weather and environmental conditions also vary greatly within this area. Regional vegetation becomes "conditioned" to withstand different environmental conditions, which also influences de-energization thresholds. Idaho Power developed windspeed considerations, which it will continue to refine with additional data and weather technology based on historic wind conditions compared to system outage information.

8.13. Engineering Assessment

Idaho Power follows robust transmission and distribution maintenance and inspection practices. When a potential PSPS event is identified, Idaho Power's T&D Maintenance and Engineering department will evaluate potential impacts to current or planned maintenance activities.

8.14. Alternative Protective Measures

Considering the significant potential impact of a PSPS to customers, Idaho Power will thoroughly evaluate other potential alternatives for reducing wildfire risk prior to implementing a PSPS.

8.15. Real-time Field Observations

Idaho Power uses SGMs for various purposes on its the distribution systems, including communication (where available) to provide near real-time information and to detect wind speed with anemometers. This information is displayed on a GIS viewer and used to inform Idaho Power's evaluation and decision-making during storm events.

Idaho Power may also deploy field personnel to evaluate if a PSPS event should be initiated.

8.16. Other

Idaho Power plans to evaluate expanding existing capabilities to enhance weather forecasting and add new capabilities to detect fires.

9. RESPONSIBILITIES

Developing and implementing PSPS protocol involves various groups throughout the company. Below is a non-exhaustive list of responsibilities by department, representatives of which will work together to promote organized, consistent and safe implementation of PSPS events.

9.1. Load Serving Operations

- Develop and implement safe and reliable power shutoff protocols and procedures
- Ensure System and Regional Dispatch employees are appropriately trained to perform relevant responsibilities under this PSPS Plan, and that such employees receive timely information regarding wildfire risk and weather conditions for purposes of performing those responsibilities in the event of a PSPS
- Assist with PSPS evaluation and decision-making

- Safely restore service to PSPS areas when notified by Customer Operations it is safe to re-energize
- Provide required notifications to public safety partners to enhance public safety
- Participate in After-Action Reviews (AAR) (further discussed in Section 13 below) and ensure modifications to PSPS protocol are implemented as necessary

9.2. Atmospheric Science

- Monitor daily, weekly and long-term weather forecasts
- Monitor fuels conditions and trends
- Monitor Fire Weather Watches, Red Flag Warnings and High Wind Watches and Warnings
- Communicate with external agencies for increased situational and conditional awareness. Increase communications as conditions require
- Communicate internally to Idaho Power's Transmission & Distribution Engineering and Reliability (TDER) senior manager when extreme conditions indicate a PSPS event is likely
- Support PSPS activities such as planning, training and exercises
- Assist in PSPS information-gathering, evaluation and decision-making
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.3. TDER Senior Manager

- Oversee wildfire mitigation program and support cross-departmental collaboration
- Monitor daily, weekly and long-term weather and wildfire forecasts
- Monitor Fire Weather Watches, Red Flag Warnings and High Wind Watches and Warnings
- Develop and lead training modules for PSPS implementation
- Activate the PSPS Assessment Team if a PSPS is likely
- Communicate with Oregon and Idaho ESF-12

- Ensure PSPS activities such as operations planning, training and exercises occur annually
- Ensure a coordinated and cohesive external and internal communication and notification plan is in place and reviewed annually
- Coordinate with Atmospheric Science to continue evaluating enhancements to situational awareness capabilities
- Participate in AARs and provide input on, and monitor as necessary, modifications to PSPS protocol

9.4. Customer Operations and T&D Construction

- Develop and implement safe and reliable power shutoff protocols and procedures
- Ensure field personnel are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Assist in PSPS information-gathering, evaluation and decision-making
- Ensure crews and equipment are available to support PSPS events
- Perform field observations, line patrols and other PSPS tasks as necessary
- Perform required repairs to safely re-energize the system after a PSPS event
- Request/obtain air patrol contractors for line inspections as required
- Participate, with assistance from Corporate Communications, in Idaho Power's general external education campaign
- Develop, with assistance from Corporate Communications, a cohesive notification framework with public safety partners while consistently evaluating ways to increase communication and outreach effectiveness
- Engage with public safety partners and critical facilities before, during and after a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.5. Supply Chain/Stores

- Ensure preparedness for wildfire season with materials readily available for restoration purposes

- Work with Customer Operations and T&D Construction in response to a PSPS event, which could include pre-event activities such as staging materials and supplies
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.6. Fleet/Equipment Resource Pool

- Ensure employees are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Ensure readiness of employees and resource pool equipment for a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.7. Supply Chain Contracting

- Ensure contract resources are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Work with Customer Operations to provide contracting resources as required
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.8. Substation Operations

- Monitor substations and perform actions to support PSPS operations
- Coordinate activities with Dispatch and Customer Operations
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.9. Corporate Communications

Corporate Communications will develop and execute PSPS communications to Idaho Power customers and employees and support other business units in their communication efforts with regulators, critical facility operators, public safety partners and other stakeholders.

Corporate Communications will:

- In coordination with Customer Operations and Regulatory Affairs, work with public safety partners, critical facilities, regulators and other stakeholders to develop a comprehensive, coordinated and cohesive customer notification framework.
- With input from public safety partners, develop and implement a wildfire education and awareness campaign focused on wildfire prevention and mitigation, PSPS awareness and outage preparedness for customers.
- In the event of a PSPS:
    - To the extent possible and in coordination with Customer Service and IT, notify customers before, during and after a PSPS event with the following information:
        - Expected timing and duration of the PSPS event
        - 24-hour contact information and website resources
    - Provide up-to-date information on a dedicated Idaho Power PSPS webpage prominently linked on the Idaho Power homepage.
    - Distribute information via media and social media channels.
- Participate in AARs and modify communication practices as necessary.

9.10. Distribution Engineering and Reliability

- Support Dispatch and Customer Operations in developing de-energization and re-energization plans for PSPS events
- Monitor and verify the protection system operated correctly after any device operations caused by events on the circuit as appropriate
- Evaluate and enact protective device setting changes as required.
- Support rapid repairs of damaged infrastructure as needed.
- Support Load Serving Operations in planning improvements to PSPS operational capabilities
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.11. Safety

- Ensure the safety professionals are appropriately trained to perform all relevant responsibilities under this PSPS Plan
- Provide PSPS training for field personnel
- Assist in AARs after a PSPS event (or potential event in which the PSPS Team is activated)

9.12. Vegetation Management

- Following de-energization, and when it is safe to do so, Customer Operations will report impacts to infrastructure and assets from vegetation, as appropriate.
Vegetation Management will then work toward removing vegetation debris necessary for re-energization.
- Ensure contractors and field personnel are appropriately trained to perform all relevant responsibilities under this PSPS Plan.
- Use reasonable efforts to ensure contract resources are available and prepared for PSPS events.
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary.

9.13. Geographic Information Systems

- Work with Customer Operations and Corporate Communications to develop PSPS boundary information for PSPS GIS maps required for the PSPS website
- Before wildfire season and during preliminary notifications of a potential PSPS event, provide relevant GIS data within the confines of applicable law to public safety partners

9.14. Customer Service

- Respond to customer calls and respond to questions with information provided by Corporate Communications
- Ensure customer service representatives are trained to manage customer interactions during a PSPS event

9.15. Communication Systems (Stations)

- Provide monitoring and on-call presence for the following:
    - Radio communications and infrastructure
    - Network infrastructure and connectivity
    - SCADA communications
- Ensure readiness to deploy mobile 2-way radio trailer during a PSPS event
- Participate in AARs and ensure modifications to PSPS protocol are implemented as necessary

9.16. Customer Operations Support

- May lead AARs to ensure modifications to PSPS protocol are implemented as necessary

9.17. Legal

- Provide legal guidance in evaluating a potential PSPS event
- May direct AARs after a PSPS event (or potential event in which the PSPS Team is activated)
- May be involved in reviewing communications to customers, public safety partners and critical facilities

9.18. Regulatory

- May provide regulatory guidance in evaluating a potential PSPS event
- May be involved in reviewing communications to customers, public safety partners and critical facilities
- Assist in/direct regulatory reporting/filing activities

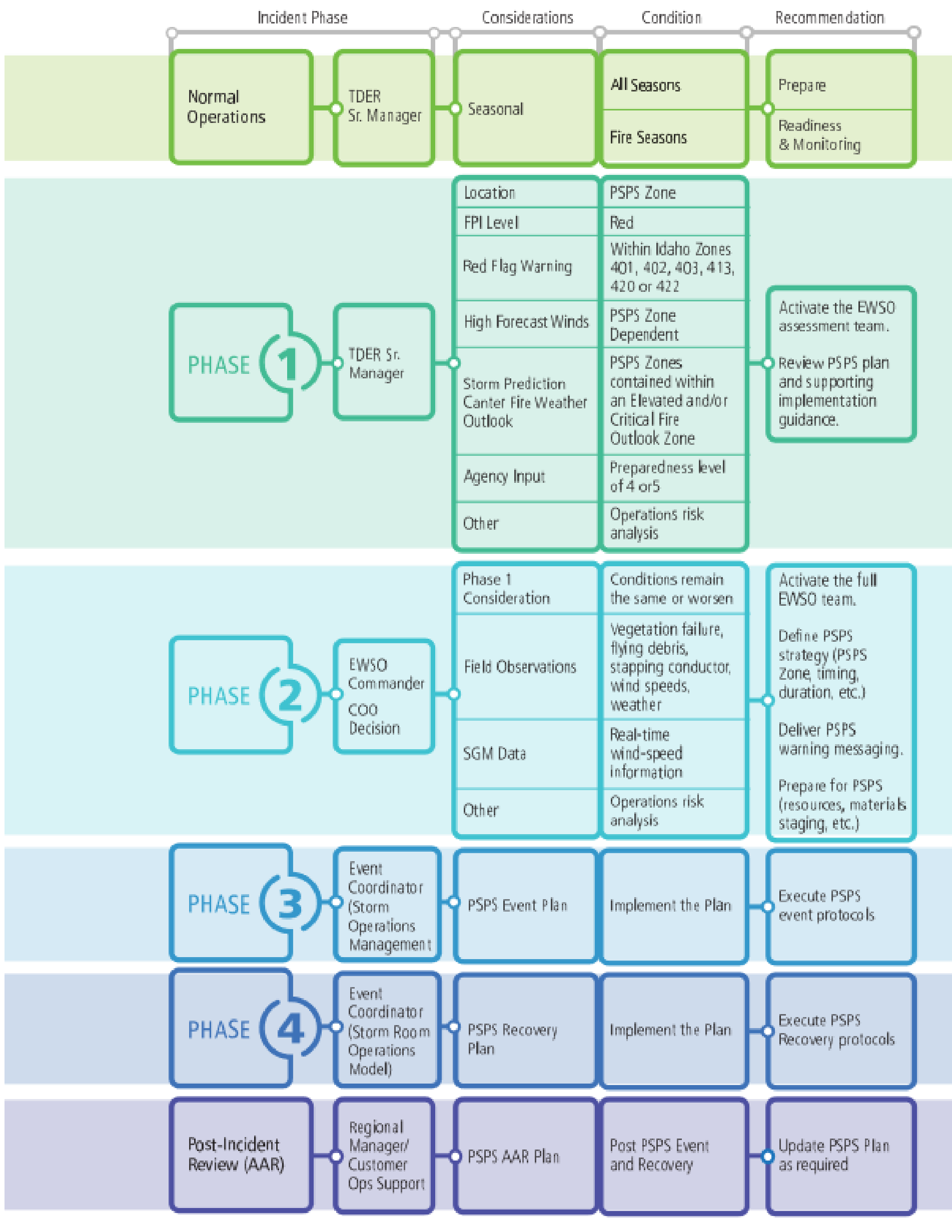
10. PSPS Operations

10.1. General

Section 11 details the phases, and protocol within each phase, of a PSPS event. Additional procedures are found in plans linked below and the attached Appendices as referenced herein.

Table 2 below summarizes the PSPS phases.

Table 1
Incident phase decision triggers



10.2. PSPS Preparedness

PSPS preparedness is a cyclical effort involving Idaho Power, public safety partners, state and local governments, communities and customers. Idaho Power's main objectives of preparedness are: 1) performing wildfire prevention and mitigation activities; and 2) engaging with external public safety partners, critical facilities and communities to develop relationships and provide education to safely and effectively implement this plan. The TDER senior manager coordinates and facilitates activities of multiple Idaho Power business units for wildfire prevention and mitigation activities while Customer Operations and Corporate Communications facilitates public outreach and coordination efforts with external stakeholders.

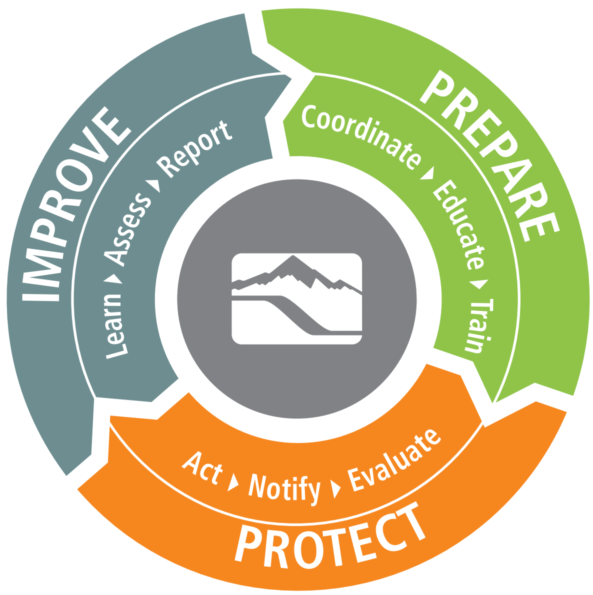


Figure 1
PSPS Preparedness Cycle

Idaho Power's goal is to take a community approach to wildfire preparedness by educating and encouraging individual preparedness and relying on existing protocols and procedures currently available through local governments and emergency response professionals.

10.2.1. Idaho Power Programs

Idaho Power's WMP facilitates PSPS preparedness through vegetation management protocol specific to wildfire season, distribution and transmission hardening efforts, situational awareness coinciding with wildfire operational protocol, training programs, communications strategies and coordinated planning with both internal and external stakeholders. This PSPS Plan and emergency response protocol correspond with Idaho Power's WMP preparedness measures in an effort to further reduce wildfire risk consistent with industry best practices and regulatory requirements.

10.2.2. Coordination with Government Entities

Coordination with local government and emergency response entities is critical to Idaho Power's reliance on existing protocols and procedures developed by these external stakeholders. Customer Operations engages in these coordination efforts through ongoing communications and additional activities as required by this Plan. Activities include, without limitation:

- Being a trusted energy advisor to mayors, city managers, county leaders, elected officials and other stakeholders
- Educating and encouraging individual preparedness
- Educating stakeholders about Idaho Power wildfire preparedness and mitigation efforts, PSPS planning and capabilities
- Enhancing relationships with external stakeholders for improving interoperability and wildfire coordination
- Enhancing relationships with community services partnerships

10.2.3. Community Preparedness

Engage with public sector agencies and communities where PSPS events are likely to leverage existing emergency response plans and resources to increase the effectiveness of PSPS communications.

10.2.4. Information Sharing

Coordinate with public safety partners in advance of a PSPS event to prepare information needed by these partners and establish communication protocols for critical decision-making before and during a PSPS event, including restoration activities.

10.2.5. Notifications and Emergency Alerts

Collaborate with agencies in advance of PSPS events to allow for use of existing notification methods to communicate effectively during PSPS events.

10.2.6. Training and Exercises

Coordinate and participate in tabletop exercises with public safety partners to enhance knowledge of each other's emergency operations for smooth interactions during PSPS events.

10.3. Proactive Communications

Although the size of Idaho Power's service area, geographic and environmental diversity, and unpredictable nature of Idaho and Oregon weather make it challenging, Idaho Power is committed to providing as much advance notice as reasonably possible in preparation for a PSPS event. Table 3 provides Idaho Power's optimal communication timeline for PSPS events, circumstances permitting.

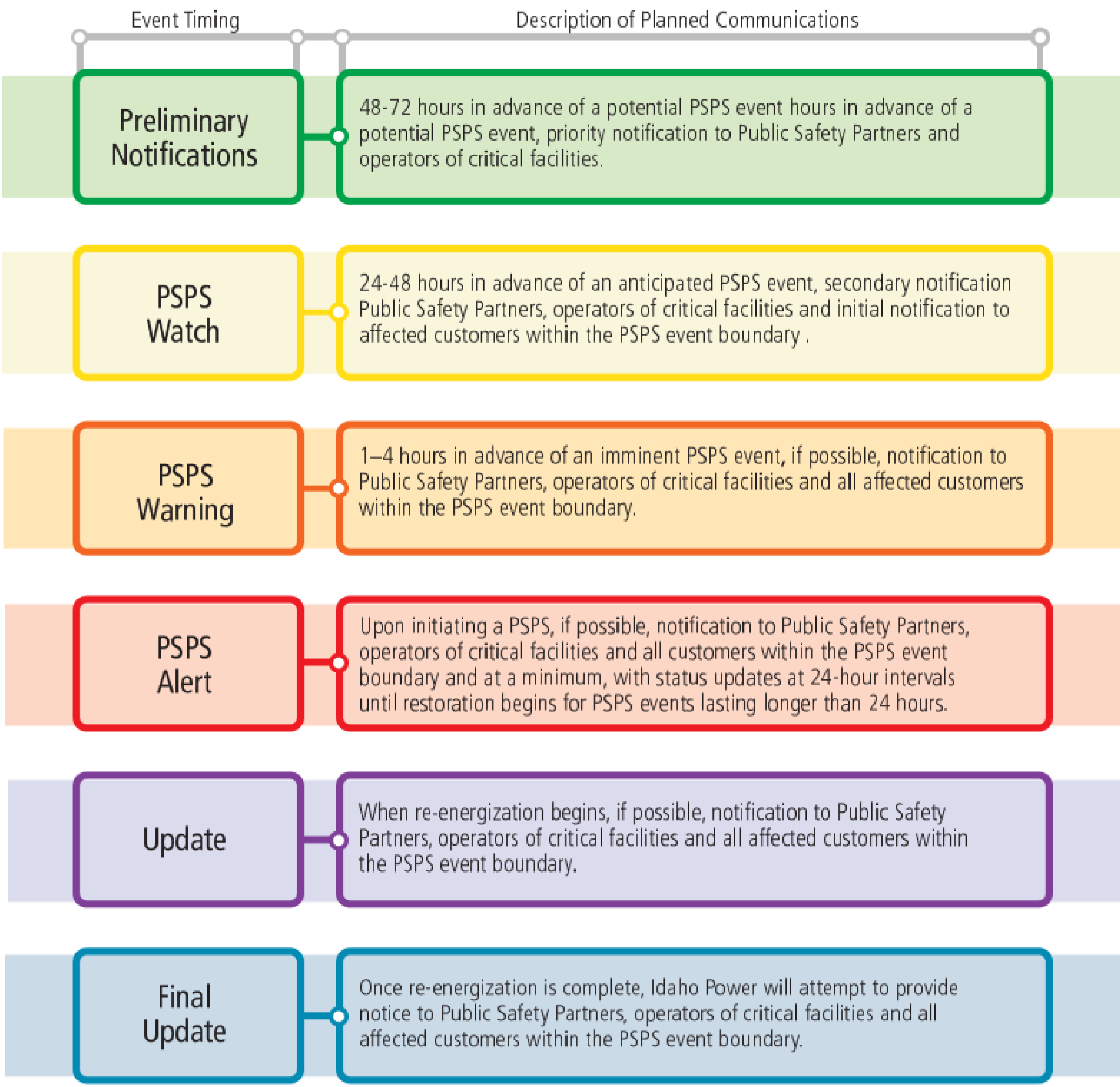


Figure 2
PSPS Event Communication Timeline

10.4. Wildfire Season Operations

As described here and in Idaho Power's WMP, normal operations during wildfire season differs from normal operations during the rest of the year based on heightened requirements specifically targeted at predicting and reducing wildfire risk.

10.4.1. Situational Awareness Activities

During wildfire season, Idaho Power closely monitors fire conditions and weather patterns. Idaho Power's Atmospheric Science team prepares a monthly "Seasonal Wildfire Outlook" report beginning in April and continuing through wildfire season containing information on regional drought conditions obtained from the National Drought Monitor, weather and climate outlook, seasonal precipitation and temperature outlooks from NOAA and the NWS, and a regional wildfire outlook.

During wildfire season, the Atmospheric Scientists will determine a daily FPI as described in Section 5.2 of the WMP describing shorter-term weather and fire conditions specific to WMP risk zones across Idaho Power's service territory and in identified risk zones where transmission facilities extend beyond service territory boundaries.

10.4.2. GIS Wildfire Information

Idaho Power's GIS team pulls regional wildfire information from a feature layer sourced by the GIS mapping software company ESRI, which pulls the data from the Integrated Reporting of Wildland-Fire Information (IRWIN) and the National Interagency Fire Center (NIFC). This information is added to multiple GIS viewers utilized by Idaho Power employees. These viewers also overlay current wildfire information to geospatially show physical relationships to transmission and distribution lines which provides valuable situational awareness in understanding wildfire activity near Idaho Power's T&D systems. This information is updated near real-time.

10.4.3. Key Grid Interdependent Utilities and Agencies

Idaho Power exchanges dispatch information with key grid interdependent utilities and energy providers to expedite communication and coordination during wildfire events. These contacts include Avista, Bonneville Power Administration, Northwestern Energy, NVEnergy, Oregon Trail Electric Cooperative, PacifiCorp, Raft River Electric, Seattle City Light and U.S. Bureau of Reclamation. Idaho Power also exchanges dispatch information with NIFC, BLM Fire Dispatch and various National Forest Service District Offices—including Idaho Power dispatch receiving BLM and US Forest Service incident command information during wildfire events—to improve communication and coordinate fire-related activities.

10.5. Phase 1

The decision to implement a PSPS event will be based on the best available data for weather and other fire-related conditions as detailed above in Section 8—PSPS Implementation Considerations. Multiple events may require simultaneous management such as other storm-related outages or other PSPS events.

10.5.1. PSPS Assessment Team Activation

Idaho Power will transition from normal wildfire season operations to Phase 1 of a PSPS event at the direction of the TDER senior manager. During Phase 1, Idaho Power will activate the PSPS Assessment Team, which includes the TDER senior manager, a regional senior manager of the area potentially impacted, Load Serving Operations (LSO) senior manager, a documentation subject matter expert (SME), and representatives from the Atmospheric Science team and Corporate Communications. The PSPS Assessment Team will hold conference calls as needed to discuss current and forecasted weather conditions and other critical information regarding a potential PSPS event. The TDER senior manager will facilitate PSPS Assessment Team meetings and conference calls and the PSPS Assessment Team will be responsible for determining whether to recommend maintain Phase 1, escalate to Phase 2, or de-escalate to normal operations. The PSPS Assessment Team will decide if Idaho Power will issue a preliminary notification of a potential PSPS event to public safety partners, critical facilities operators and ESF-12 as described in Table 3 above. During Phase 1, the PSPS Assessment Team will review the PSPS Plan and supporting documents. An operational risk assessment will be performed as well to determine current operational factors (existing outages, facilities under construction, personnel availability, etc.), risks and vulnerabilities. Ultimate determination will be made whether to escalate to Phase 2 by the TDER senior manager. Within one hour of Phase 2 notification, the full PSPS team will be placed on stand-by and team member availability will be determined. The full PSPS team is the PSPS Assessment Team plus the VP of Planning, Engineering and Construction, the Customer Operations VP and VP of Power Supply or their assigns.

10.5.2. Community Notifications

Depending on the situation and timing, public safety partners and critical facility operators may be notified during this phase. These notifications may include emails, text messages and/or phone calls as described in Idaho Power internal processes and procedures.

10.6. Phase 2

Phase 2 actions are determined by additional situational awareness activities, timing of forecasted weather events and risk tolerance. Upon transitioning to Phase 2, Idaho Power will provide external notifications as called out in Table 3 above with specific roles and responsibilities as described in internal process and procedure documents.

10.6.1. Activate Event Coordinator

Idaho Power will assign an Event Coordinator as outlined in Wildfire Mitigation and PSPS Plan. The event coordinator's main role is to coordinate activities across the region associated with PSPS implementation and restoration.

10.6.2. Conduct Operational Risk Analysis

The PSPS Assessment Team will present its operational risk analysis recommendation to the VP of PEC, VP of Customer Operations and the COO who will then evaluate the PSPS Assessment Team's recommendation, and the COO will make the final determination of whether to proceed to Phase 3 implementation of a PSPS event.

10.6.3. Request to Delay a PSPS Event

There may be requests to delay proactive de-energization from the public safety partners. This may occur for several reasons, with the most anticipated being loss of power for pumping water to fight wildfires. Delay requests should be routed through dispatch and sent to the PSPS Team for evaluation. The PSPS Team will provide the COO a recommendation on whether to approve the proactive de-energization delay and the COO will make the final decision. As soon as practicable after receiving the request, Idaho Power will notify the ESF-12 liaison of the delay request and basis of such request, as well as the final determination and the underlying justification.

10.6.4. PSPS Event Strategy

Regional operations personnel developed action plans and switching orders as part of their preparedness activities. These plans and switching orders will be reviewed and refined as necessary based on the current and forecasted conditions and will include situation-specific tactics and detailed instructions.

10.6.5. Field Observations and Response Teams

Regional Operations will coordinate field personnel to be mobilized and dispatched to strategic locations, including areas with limited weather and system condition visibility, to perform field observations for on-the-ground, real-time information critical to inform decisions on proactive de-energization. Field observations include—without limitation—conditional assessments of system impacts from wind and vegetation, flying debris and slapping conductors.

10.6.6. Customer and Community Notifications

Depending upon the timing and situation, Idaho Power may use various forms of communication (including media outreach) to provide information and updates to public safety partners, critical facility operators, and customers, particularly those impacted by the PSPS event. Information and updates will include the reason for the potential de-energization, where to find real-time updates on outage status and other relevant safety and resources. Internal processes and procedures will be followed to ensure accurate, up-to-date communication is provided.

10.7. Phase 3

Upon the COO making a determination to proactively de-energize, the LSO representative of the PSPS Team will inform System and Regional Dispatch Operations and request coordination of the estimated time to begin the PSPS. The regional manager, or their assigned representative of the region in which the PSPS will take place, will coordinate with the event coordinator to pre-position field personnel where manual de-energization is required and to stand by for orders to de-energize. System and Regional Dispatch Operations will implement the PSPS according to their established processes. Stations and communications system operations personnel will be prepared to support PSPS activities as needed. Idaho Power will take the following community-centered actions as soon as safely possible. Regional teams will follow internal processes and procedures to safely and effectively implement a PSPS event.

10.7.1. Customer and Community Notification

Relying on internal processes and procedures, Idaho Power will use various forms of communication (including media outreach) to provide information and updates to customers and other stakeholders, particularly those impacted by the PSPS event. Information and updates will include the reason for the de-energization, where to find real-time updates on outage status and other relevant safety and resource information regarding the PSPS. Specific protocols may be included in individual work group plans.

10.8. Phase 4

10.8.1. System Inspections

When it is safe to do so, Idaho Power will begin line patrolling activities to inspect T&D circuits and other potentially impacted Idaho Power facilities. Patrol personnel will report system conditions back to System and Regional Dispatch Operations for coordination with field crews. Patrols will be performed as required to ensure conditions and equipment are safe to re-energize.

10.8.2. Repair and Recovery

Line crews will repair T&D facilities as coordinated with System and Regional Dispatch Operations, replacing damaged equipment and performing other actions to support safe re-energization of the T&D system.

10.8.3. Incident Management Support

Support throughout the PSPS event will continue as described in Idaho Power's Wildfire Mitigation and PSPS Operational Plan. The PSPS Team will continue to monitor fire and weather conditions. Logistics and mutual assistance requirements will be determined and acted upon per existing plans and processes. If timely re-energization is not possible based on the magnitude of the event, the EMT will be notified for additional support.

10.8.4. Communicate PSPS Event Conclusion

Idaho Power will use various forms of communication (including media outreach) to inform customers and other stakeholders, particularly those impacted by the PSPS event, when repairs are complete and it is safe to re-energize the system. This may occur in stages as different feeders or feeder sections are repaired and safe to re-energize. This will be viewable on the outage map on Idaho Power's website during the event. Idaho Power will also leverage existing public agency outreach and notification systems as done at other points in the PSPS process.

10.8.5. Re-energization

Once re-energization activities are completed and service is restored, crews and support staff will demobilize and return to normal fire season operations as described in internal process and procedure documents.

10.9. Post-incident Review

During the PSPS phases the documentation SME will collect and maintain in the Regional Dispatch Operations logs incident information required for reporting purposes.

Following conclusion of a PSPS event, the Regional Manager or their assigned representative will conduct informal, high-level debriefs to identify potential modifications to PSPS protocol based on lessons learned during the event. The regional manager or assigned representative will consolidate the feedback and provide to the documentation SME.

Also following the PSPS event, the TDER senior manager will conduct an AAR with the PSPS Team to identify potential modifications to PSPS protocol based on lessons learned during the event. The TDER senior manager will consolidate the feedback and provide to the documentation SME.

After wildfire season, the Customer Operations support leader may conduct an AAR focusing on operational processes, communications, customer support as well as emergency response and restoration. Idaho Power may also request feedback from external stakeholders on coordination efforts, communications and outreach effectiveness for integration into the AAR report.

11. Financial Administration

Idaho Power will track expenses related to PSPS events for OPUC and IPUC reporting and potential recovery. Expense should be tracked for the entire PSPS event (Phase 1 through conclusion of the Post-Incident Review and filing the PSPS event report with the OPUC) to include, without limitation, time reporting, equipment and supplies used to set up customer resource centers and provided to customers (e.g., water, ice, etc.)

12. Reporting

Employees are required to manage information regarding PSPS events pursuant to Idaho Power's Information Retention Policy and underlying standards. Idaho Power will submit reports to the IPUC and OPUC as required.

13. After-Action Report

An AAR is a structured review or de-brief process used to evaluate the effectiveness of the Plan and potential areas for improvement. This process may be performed after a PSPS event and may be confidential at the direction of Legal to improve the PSPS processes and procedures.

14. Training

Idaho Power will strive to provide annual training, prior to or shortly after the beginning of wildfire season, to relevant employees on their respective roles in performing this PSPS Plan.

15. Exercises

Idaho Power will exercise this PSPS Plan at least annually using various scenarios and testing all or any portion(s) of the Plan which may include:

- Testing text and/or phone alerts with a test group of public safety partners
- Testing tactical operational plans such as reporting field observations or positioning employees at manually operated disconnects to test timing for de-energization and field inspections of T&D assets
- Discussing and/or practicing roles and responsibilities of both strategic and tactical operations, including decision-making handoffs and hypothetical scenarios
- Discussing and/or developing re-energization plans
- Testing capacity limits on incoming and outgoing communications systems

Appendix C
Oregon Wildfire Requirements and Recommendations.

Oregon Requirements and Recommendations

This appendix provides additional information specific to wildfire-related requirements, as well as wildfire-related recommendations, in Oregon.

Oregon Administrative Rule (OAR) Requirements

Below is a mapping of wildfire mitigation plan rules to sections within Idaho Power's WMP.

Wildfire Protection Plan Filing Requirements—OAR 860-300-0020

Oregon Requirement—OAR 860-300-0020	Corresponding Location in WMP
(1) Wildfire Protection Plans and Updates must, at a minimum, contain the following requirements as set forth in Section 3(2)(a)-(h), chapter 592, Oregon Laws 2021 and as supplemented below: *(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are:*	See Section 3: Quantifying Wildland Fire Risk See Idaho Power website for details of wildfire risk zones outside of service territory
(A) Within the service territory of the Public Utility, and *(B) Outside the service territory of the Public Utility but within the Public Utility's right-of-way for generation and transmission assets.*	See Section 3.2.2: Wildfire Risk Areas See Figure 3: Boardman to Hemingway (B2H) Proposed Route Risk Zones
(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.	See Section 4: Costs and Benefits of Wildfire Mitigation
(c) Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.	See Section 5: Situational Awareness; Section 6: Mitigation—Field Personnel Practices; Section 7: Mitigation—Operations; Section 8: Mitigation—T&D Programs; and Section 8.3: T&D Vegetation Management
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	See Section 10.2 Community Outreach and Section 10.2.1: Community Engagement See Appendix B: Idaho Power's Public Safety Power Shutoff Plan, Section 10.2.1: Coordination with Government Entities and Section 10.2.2: Community Preparedness
(e) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	See Section 7.4: Public Safety Power Shutoff and Appendix B: Idaho Power's Public Safety Power Shutoff Plan
(f) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season.	See Section 10: Communicating About Wildfire

Oregon Requirement—OAR 860-300-0020	**Corresponding Location in WMP**
(g) Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire.	For Transmission, see Section 8.2.1: Transmission Asset Management Programs (with information on aerial, ground, detailed visual, pole, and other protection programs) For Distribution, see Section 8.2.2: Distribution Asset Management Programs (with information on visual, pole, and line equipment inspection programs)
(h) Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in in areas the Public Utility identified as heightened risk of wildfire.	See Section 8.3.2: Transmission Vegetation Management and Section 8.3.3: Distribution Vegetation Management
(i) Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.	See Section 4: Costs and Benefits of Wildfire Mitigation, specifically Section 4.3: Wildfire Mitigation Cost Summary and Section 4.4: Mitigation Activities
(j) Description of participation in national and international forums, including workshops identified in Section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used develop implement cost effective wildfire mitigation solutions.	See Section 2: Government, Industry, and Peer Utility Engagement

Risk Analysis—OAR 860-300-0030

Oregon Requirement—OAR 860-300-0030	**Corresponding Location in WMP**
(1) The Public Utility must include in its Wildfire Mitigation Plan risk analysis that describes wildfire risk within the Public Utility's service territory and outside the service territory of the Public Utility but within the Public Utility's right of way for generation and transmission assets. The risk analysis must include, at a minimum: *(a) Defined categories of overall wildfire risk and an adequate discussion of how the Public Utility categorizes wildfire risk. Categories of risk must include, at a minimum:*	See Section 3: Quantifying Wildland Fire Risk See Section 3.2.2: Wildfire Risk Areas and risk zone map on Idaho Power's website for detailed map of wildfire risk zones
(A) Baseline wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple years. Examples include topography, vegetation, utility equipment in place, and climate; *(B) Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year or from year to year; Examples include cumulative precipitation, seasonal weather conditions, current drought status, and fuel moisture content;* *(C) Risks to residential areas served by the Public Utility; and*	See Section 3.2 for discussion of fixed risk elements See Section 3.2.1 for discussion of variable risk elements that change throughout the year See Section 3.2.1 paragraph 4 addresses the consideration of residential areas in risk analysis

Oregon Requirement—OAR 860-300-0030	Corresponding Location in WMP
(D) Risks to substation or powerline owned by the Public Utility.	See Section 3.2.1 paragraph 4 addresses overhead power lines. Note: Idaho Power does not model wildfire progression or spread within substations due to zero vegetation within the fenced area. Also see Section 3.2.2.1 for discussion of risk modeling of proposed Boardman to Hemingway transmission line
(b) a narrative description of how the Public Utility determines areas of heightened risk of wildfire using the most updated data it has available from reputable sources.	See Section 3.2.2: Wildfire Risk Modeling Process and the 2023 Risk Modeling Update
(c) a narrative description of all data sources the Public Utility uses to model topographical and meteorological components of its wildfire risk as well as any wildfire risk related to the Public Utility's equipment.	See Section 11.4: Wildfire Risk Map
(A) The Public Utility must make clear the frequency with which each source of data is updated; and *(B) The Public Utility must make clear how it plans to keep its data sources as up to date as is practicable.*	See Section 11.4: Wildfire Risk Map
(d) The Public Utility's risk analysis must include a narrative description of how the Public Utility's wildfire risk models are used to make decisions concerning the following items: *(A) Public Safety Power Shutoffs* *(B) Vegetation Management;* *(C) System Hardening;* *(D) Investment decisions; and* *(E) Operational decisions.*	A) See Section 7.5.2: PSPS Plan B) See Section 8.3: T&D Vegetation Management C) See Executive Summary on Infrastructure Hardening; Section 8.2.2: Distribution Asset Management Programs; Section 11.9: Long-Term Metrics D) Risk analysis informs Red and Yellow Risk Zones mitigation activities. See Section 4: Costs and Benefits of Wildfire Mitigation and Section 4.4 Mitigation Activities E) See Section 7.2: Operational Protection Strategy and Appendix A: Wildland Fire Preparedness and Prevention Plan
(e) For updated Wildfire Mitigation Plans, the Public Utility must include a narrative description of any changes to its baseline wildfire risk that were made relative to the previous plan submitted by the utility, including the Public Utility's response to changes in baseline wildfire risk, seasonal wildfire risk, and Near-term Wildfire Risk.	For the 2023 WMP, Idaho Power did not make changes to baseline wildfire risk, but will evaluate and discuss changes in the 2024 WMP.

Oregon Requirement—OAR 860-300-0030	Corresponding Location in WMP
(2) To the extent practicable, the Public Utility must confer with other state agencies when evaluating the risk analysis included in the Public Utility's Wildfire Mitigation Plan.	See Executive Summary section on Lessons Learned: Community Feedback

Wildfire Mitigation Plan Engagement Strategies—OAR 860-300-0040

Oregon Requirement—OAR 860-300-0040	Corresponding Location in WMP
(1) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Mitigation Plan Engagement Strategy. The Wildfire Mitigation Plan Engagement Strategy will describe the utility's efforts to engage and collaborate with Public Safety partners and Local Communities impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum: *(a) Accessible forums for engagement and collaboration with Public Safety Partners, Local Communities, and customers in advance of filing the Wildfire Mitigation Plan. The Public Utility should provide, at minimum:* *(A) One public information and input session hosted in each county or group of adjacent counties within reasonable geographic proximity and streamed virtually with access and functional needs considerations; and* *(B) One opportunity for engagement strategy participants to submit follow-up comments to the public information and input session.*	See Section 10: Communicating About Wildfire See Section 10.2: Community Outreach and Section 10.2.1: Community Engagement See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(b) A description of how the Public Utility designed the Wildfire Mitigation Plan Engagement Strategy to be inclusive and accessible, including consideration of multiple languages and outreach to access and functional needs populations as identified with local Public Safety Partners.	See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(2) The Public Utility must include a plan for conducting community outreach and public awareness efforts in its Wildfire Mitigation Plan. It must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities.	See Section 10.2.1: Community Engagement and Section 10.3.1: Key Communication Methods
(a) The community outreach and public awareness efforts will include plans to disseminate informational materials and/or conduct trainings that cover: *(A) Description of PSPS including why one would need to be executed, considerations determining why one is required, and what to expect before, during, and after a PSPS;* *(B) A description of the Public Utility's wildfire mitigation strategy;* *(C) Information on emergency kits/plans/checklists;* *(D) Public Utility contact and website information.*	For (A) – (D), see Section 10.2.1: Community Engagement; Section 10.3: Customer Communications; and Section 10.3.1: Key Communication Methods

Oregon Requirement—OAR 860-300-0040	Corresponding Location in WMP
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure. *(b) In formulating community outreach and public awareness efforts, the Wildfire Mitigation Plan will also include descriptions of:* *(A) Media platforms and other communication tools that will be used to disseminate information to the public;* *(B) Frequency of outreach to inform the public;* *(C) Equity considerations in publication and accessibility, including, but not limited to:* *(i) Multiple languages prevalent to the area;* *(ii) Multiple media platforms to ensure access to all members of a Local Community.*	See Section 10.2.1: Community Engagement For (A)-(C): See Section 10.2.1: Community Engagement; Section 10.3: Customer Communications, and Section 10.3.1: Key Communication Methods
(3) The Public Utility must include in its Wildfire Mitigation Plan a description of metrics used to track and report on whether its community outreach and public awareness efforts are effectively and equitably reaching Local Communities across the Public Utility's service area.	See Section 10.3.3: Communication Metrics
(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the Public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specified in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0050. The Coordination Strategy should include, at a minimum: *(a) Meeting frequency and location determined in collaboration with Public Safety Partners;* *(b) Tabletop Exercise plan that includes topics and opportunities to participate;* *(c) After action reporting plan for lessons learned in alignment with Public Safety Partner after action reporting timeline and processes.*	See Section 10.2.1: Community Engagement

OPUC Order Nos. 22-133 and 22-312

This appendix also addresses recommendations received from Oregon Public Utility Commission (OPUC) Staff in Docket No. UM 2209 and approved by the OPUC Order Nos. 22-133 and 22-312. The italicized text below reflects OPUC Staff's specific recommendations for the company.

Recommendations Pertaining to OPUC Order No. 22-312

Category: Cost Allocation

1) *Provide detailed cost allocation assumptions of the transmission and distribution patrol, maintenance, and repair program, separated by transmission and distribution, as well as any associated maintenance and repair program including justification and reasoning for the cost allocation between Idaho and Oregon.*

2) *Provide details explaining the proposed cost allocation between Idaho and Oregon associated with wildfire mitigation program capital investments.*

Idaho Power removed the cost allocation information contained in an earlier version of the WMP, as the WMP is intended as an evolving document and not one related to prudency of specific investments.

To address Staff's interest in this subject, the company will file a wildfire mitigation-related cost deferral application with the OPUC in December 2022 so it may be reviewed in concert with the 2023 WMP.

Category: Risk Framework

3) *Provide detailed explanation of the strategy pertaining to its risk analysis framework.*

See Executive Summary of WMP. Idaho Power carried out a review of risk management processes and will consider the ISO 31000-2018 framework and process in the 2023 WMP.

Recommendations Pertaining to OPUC Order No. 22-133

The following summarizes OPUC Staff's recommendations for the company to include in its 2023 WMP.

Risk Modeling—OAR 860-300-0020 (1)(a)(A) & (B):

1) *Provide details regarding the mileage of overhead facilities that lie within its designated YRZs and RRZs.*

See Section 3.2.2. for details of overhead line mileage in designated wildfire risk zones.

2) *Idaho Power provide details of the analysis completed for establishing the risk tiers and the threshold values utilized for classifying the YRZs and RRZs.*

See Section 3.2.2. Tier levels were established based on quantitative results of modeling and numerous workshops held with our consultant and individuals having local knowledge of topography, fuels, fire history, and overhead facilities in their area. Tier levels were generated algorithmically as a starting point in the analysis and refined through workshops. Idaho Power did not base tier levels solely on risk scores.

3) *Idaho Power provide information regarding an analysis of the risk from specific utility asset types.*

See Section 3.2.1. The company used equal probability of ignition occurring on overhead transmission and distribution facilities in quantifying wildfire risk. As we mature our risk modeling methodology, the company plans to include reliability data to improve risk models.

4) *Idaho Power provide details of the process and timing that will be followed to evaluate the established heightened wildfire risk zones, and what data inputs and portions of the analysis will be reviewed annually.*

See sections 3.2.1. and 11.4. Idaho Power is planning to update its risk modeling in 2023.

5) *Idaho Power address the concerns raised by STOP B2H Coalition as thoroughly as possible.*

Idaho Power met with Stop B2H Coalition representative Jim Kreider on November 11, 2022, to provide an overview of the risk analysis performed for the Boardman to Hemingway (B2H) route. A presentation was delivered that highlighted Idaho Power's approach to quantifying wildfire risk and provided details of analysis performed along the B2H route that exceeded analysis performed in other locations within the service area. Risk analysis conducted along the B2H route includes quantifying wildfire risk similarly to other overhead facilities as described in Section 3. In addition, the following was also performed:

- Analysis of surface fuels within 1 mile of the B2H route to determine the potential of crown fire
- Determination of the influence of topographical slope on resistance to control and spread rate within 1 mile of the B2H route
- A review of temperature, precipitation, and relative humidity of the project site
- A review of the wildland urban interface and estimation of land use area within 1 and 10 miles of the project site
- A review of historic ignitions and the perimeter of historic fires within 50 miles of the project site going back 50 years

Transmission design engineers at Idaho Power also reviewed the design of lattice and H-frame structures proposed for B2H construction. A review was performed to identify the design characteristics that lead to decreased potential of ignition. This information was shared with Mr. Kreider and the overall fire potential for the area surrounding Morgan Lake. Mr. Kreider provided good feedback and recommended that Idaho Power meet with the new fire chief for the La Grande Rural Fire District and Baker County to compare risk maps and methodology. Idaho Power agreed and will have more engagement with Mr. Kreider and agencies in 2023. Additionally, the company plans to include the B2H route when reconducting risk modeling in 2023.

WMP Effectiveness—OAR 860-300-0020 (1)(b):

6) *Include a description of how it will measure the overall effectiveness of its wildfire mitigation activities, as well as information on wildfires in the service territory for the prior year.*

See the Executive Summary and Section 11.9. Metrics include tracking and monitoring mitigation programs to identify gaps and areas requiring corrective action. Long-term metrics were incorporated in 2022 to track potential drivers of ignition with respect to outage counts.

Plan Objectives—OAR 860-300-0020 (1)

7) *Idaho Power include details on whether the objectives of key preventative actions outlined in previous year's WMP have been met.*

See the Executive Summary.

8) *Idaho Power describe, to what degree, the preventable measures outlined in previous year's WMP have reduced the risk of the utility's infrastructure from causing ignitions.*

See Section 11.9. Idaho Power believes that mitigation activities have reduced wildfire risk but we need more time in concluding the magnitude of risk reduction. Idaho Power expects that reliability data and outage analytics will provide greater confidence of risk reduction with time.

9) *Idaho Power describe any adjustments made to its wildfire prevention programs that were included in previous year's WMP.*

See the Executive Summary. Adjustments were made to pre-season wildfire patrols due to snow levels. Also, Idaho Power did not meet all vegetation management production goals set for the year and had to adjust quality assurance and control audits from 100% in wildfire risk zones to a random sample approach.

Outreach Efforts—OAR 860-300-0020 (1)(d)

10) *Idaho Power include more detailed information about how it used learnings from the previous year to improve its 2023 Plan. The company should consider Public Safety Partner input through After Action Reports (from exercises and events), surveys or other feedback mechanisms, and company lessons learned.*

See the Executive Summary and Section 10.2.1.

11) *Idaho Power include clarification about CRCs in its 2023 WMP Update, to include:*

See sections 10.2.1. and 10.2.2.

12) *Idaho Power incorporate the following in its 2023 WMP:*

- *Map showing areas of its service territory at higher risk for PSPS events.*

See PSPS program in Appendix B.

- *List of Public Safety Partners the company engages with related to WMP.*

Idaho Power maintains routine contact with county emergency managers and state-level Public Safety Partners for both Oregon and Idaho. Specific contacts can be provided upon request.

- *Frequency of communication with Public Safety Partners.*

See sections 10.2.1. and 10.2.2.4.

- *Methods of communication with Public Safety Partners.*

See Section 10.2.1.

- *Feedback received from Public Safety Partners, and description of how the information influences the WMP.*

See Section 10.2.1.

Lessons Learned—OAR 860-300-0020 (1)(e)

13) *Idaho Power include previous year's lessons learned regarding de-energization of power lines to include findings from after action reports, including survey results from exercises and actual events (when available), in its 2023 WMP.*

See the Executive Summary. While Idaho Power did not call a PSPS event in 2022, there were several lessons learned from functional exercises and one near PSPS event that was subsequently canceled due to precipitation.

14) *Idaho Power include more information about the analysis completed to make their programmatic decisions of modifying system operations. The information should clarify why the company describes plans for RRZs not YRZs, and differences in system operations between transmission lines and distribution circuits.*

See Section 7.2.

Communication and Outreach—OAR 860-300-0020 (1)(f)

15) *Idaho Power incorporate the following its 2023 WMP:*

- *Examples of messaging;*
- *Selection process for methods of outreach;*
- *Determination of target audience;*

- *Metric and criteria used to evaluate effectiveness of outreach;*
- *Outcome of previous year's outreach evaluation;*
- *Description of company personnel and external resources responsible for outreach efforts;*
- *Description of timing of the outreach, including before, during, and after wildfire season;*
- *Description of Wildfire Mitigation Information/Resources maintained by the company on its website; and*
- *Description of Social Media Campaign developed and implemented by the company to inform customers about potential wildfire impacts (i.e., potential loss of power, preparedness, safety and awareness, etc.).*

See Section 10.2.

16) *Idaho Power conduct wildfire training and exercises and include a discussion about community outreach and public awareness efforts prior to the upcoming fire season to clarify these activities, and to solicit input from participating Stakeholders.*

See the Executive Summary and Section 10.2.

Asset Inspections—OAR 860-300-0020 (1)(g)

17) *Idaho Power clearly identify inspection and correction procedures and protocols for non-wildfire risk zones, inspection and correction procedures and protocols for RRZs, and inspection and correction procedures and protocols for YRZs, along with the impacted line miles and structure counts for transmission and distribution assets in Oregon.*

See Section 3.2.2. for line miles in wildfire risk zones and Section 8.2. for details of programs taking place in those zones.

18) *Idaho Power include logic and details of analysis completed for their inspection and correction programming decisions in YRZs (and if any future RRZs) in Oregon.*

See Section 8.2.

Vegetation Management—OAR 860-300-0020 (1)(h)

19) *Idaho Power clearly identify vegetation management practices and protocols for non-wildfire risk zones, vegetation management practices and protocols for RRZs, and vegetation management practices and protocols for YRZs, along with the impacted line miles and structure counts for transmission and distribution assets in Oregon.*

See Section 8.3.

20) *Idaho Power provide logic and details of analysis completed for their programming decisions in YRZs (and if any future RRZs) in Oregon regarding vegetation management practices and protocols.*

See sections 4.4.6. and 8.3.

21) *Idaho Power provide more information regarding their quality control/quality assurance program and audits for vegetation management work completed in the RRZs, YRZs, including measures employed and resource types.*

See sections 8.3.2. and 8.3.3.4.

22) *Idaho Power provide analysis of any historical events pertaining to its power lines, specific equipment type, vegetation, and wildfires that informed the program's design and monitoring approach.*

See Section 3.2.2.

Expert Forums—OAR 860-300-0020 (1)(i)

23) *Idaho Power discuss the impact of participation in expert forums (see OAR 860-300-0020(1)U)) on identification of solutions most likely to provide the benefits anticipated. This should include:*

- *Cited research, reports, and studies used in any analysis, unless the source is confidential.*

- *How the factors unique to the company's facilities and service territory were used when considering the applicability of specific options to its systems.*

See Section 2.3. In addition to participation in wildfire mitigation forums, Idaho Power spent significant time in 2022 developing a six-year roadmap to integrate new technology into the WMP. This consisted of researching products and meeting with 30 different companies throughout the year. We worked with the Electric Power Research Institute on gaining feedback of the performance and mitigation benefit of different technologies. Covered conductor was a key area of focus and helped develop a pilot plan. Additionally, the company has invested in the Westly Group, a fund that invests in startups focused on the digitalization and sustainability of energy, mobility, buildings, and industrial technology. One of our focus areas with the Westly Group in 2022 was reviewing new wildfire technologies.

The following were references used during the year to form changes in the 2023 WMP.

Wildfire Mitigation

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North American Electric Reliability Corporation. 2021. *Wildfire Mitigation Reference Guide*.

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Serrano, R., Carvalho, M., Araneda, J., Alamos, O., Barroso, L., Bayma, D., Ferreira, R., and Moreno, R. 2022, January/February. *Fighting Against Wildfires in Power Systems*, IEEE Power & Energy, 20(1), 38-51.

Sharafi, D., Dowdy, A., Landsberg, J., Bryant, P., Ward, D., Eggleston, J., and Liu, G. 2022, January/February. *Wildfires Down Under.* IEEE Power & Energy, 20(1), 52-63.

Udren, E. Bolton, C. Dietmeyer, D. Rahman, T., and Flores-Castro, S. 2022, January/February. *Managing Wildfire Risks.* IEEE Power & Energy, 20(1), 64-77.

Utility Products. 2019, October 24. *Wildfire Mitigation: Doing Your Part to Prevent the Spark. Utility Products.* www.utilityproducts.com/safety/article/14069290/wildfire-mitigation-doing-your-part-to-prevent-the-spark

Wolfram, J. Urban, J., and Guillermo, R. .2022, January/February. *Powerlines and Wildfires: Overview, Perspectives, and Climate Change.* IEEE Power & Energy, 20(1), 16-27.

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Eaton Power Systems (2021). *Overcurrent Fault Data in The Form6*

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Hou, D. 2007. *Detection of High Impedance Faults in Power Distribution Systems.* Presented at the 6th Annual Clemson University Power Systems Conference, Clemson, South Carolina.

Kirkpatrick, B., Ramdoss, R., Bolbolian, V., Ojeda, A., Swisher, and A., Rorabaugh, J. 2022, January 20). *Heading Off Southern California Wildfires: Distribution Open Phase Detection. T&D World.* www.tdworld.com/wildfire/article/21182896/heading-off-southern-california-wildfires-distribution-open-phase detection?utm_source=TW+TDW+Energizing&utm_medium=email&utm_campaign=CPS220121036&o_eid=7607D2261456E6L&rdx.ident[pull]=omeda|7607D2261456E6L&oly_enc_id=7607D2261456E6L

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Risk Management

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International Organization for Standardization. 2018. *Risk Management—Guidelines.*

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<u>Group Participation and Learnings—OAR 860-300-0020 (1)0)</u>

24) Idaho Power include more specifics on what it has learned by participating in these groups. Staff would like assurance the company is leveraging the learnings from other utilities and experts to facilitate implementation of solutions with the highest benefit cost ratio.

See Section 2.3.

25) Idaho Power include its contribution to these forums including any research projects it is supporting or participating in.

See Section 2.3.

7/7/22

Electric Utility Wildfire Mitigation Plans – Public Utility Commission of Oregon

Senate Bill 762 (2021) **https://olis.oregonlegislature.gov/liz/2021R1/SB0762/Enrolled**

SB 762 is a comprehensive, omnibus wildfire bill that establishes new electric utility system mandates to identify and assist in mitigating wildfire risks. Sections 1 – 6 impact electric systems and the PUC directly and indirectly.

Sections 3 – 5 focuses on requiring both investor-owned utilities (IOUs) and consumer-owned utilities (COUs) to operate under a risk-based wildfire protection plans. The IOUs must submit plans annually to the PUC for review and approval. The COUs must submit copies to the PUC of their wildfire mitigation plans once they have been approved by their governing body.

Investor Owned Utilities	Status	Links
Portland General Electric	Approved	UM 2208
PacifiCorp	Approved	UM 2207
Idaho Power	Conditionally Approved	UM 2209

Non-investor owned utilities file plans with the PUC under Docket RO 14:
https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22957 (individual links below)

Cooperatives	Status	Links
Blachly-Lane County Cooperative Electric Assoc.	Received 6/8/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq82616.pdf
Central Electric Cooperative, Inc.	Received 6/22/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq10634.pdf
Clearwater Power Company	Plan drafted	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq114431.pdf
Columbia Basin Electric Cooperative, Inc.	Received 6/22/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq16627.pdf
Columbia Power Cooperative Association	Received 6/21/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq14132.pdf
Columbia Rural Electric Association, Inc.	Received 7/6/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq84757.pdf
Consumers Power, Inc.	Received 6/21/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq84534.pdf
Coos-Curry Electric Cooperative, Inc.	Received 6/22/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq112353.pdf
Douglas Electric Cooperative, Inc.	Received 6/13/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq103133.pdf
Harney Electric Cooperative, Inc.	Received 3/15/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq85747.pdf
Hood River Electric Cooperative	Received 6/22/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq16944.pdf
Lane Electric Cooperative, Inc.	Received 6/30/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq171953.pdf

Midstate Electric Cooperative, Inc.	Received 6/29/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq11053.pdf
Oregon Trail Electric Consumers Cooperative	Received 6/30/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq104531.pdf
Salem Electric	Received 6/29/22	http://edocs.puc.state.or.us/efdocs/HAH/ro14hah85113.pdf
Surprise Valley Electrification Corp.	Received 4/15/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq83533.pdf
Umatilla Electric Cooperative	Received 6/21/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq125454.pdf
Umpqua Indian Utility Cooperative	Received 6/30/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq155345.pdf
Wasco Electric Cooperative, Inc.	Received 4/21/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq81642.pdf
West Oregon Electric Cooperative, Inc.	Received 6/29/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq82358.pdf

Peoples' Utility Boards	**Status**	**Links**
Central Lincoln	Received 6/30/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq164237.pdf
Clatskanie	Received 6/30/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq132246.pdf
Columbia River	Received 3/8/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq15446.pdf
Emerald	Received 6/6/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq165613.pdf
Northern Wasco	Received 8/27/21	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq9838.pdf
Tillamook	Received 6/23/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq8153.pdf

Municipalities	**Status**	**Links**
Ashland	Received 6/22/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq91017.pdf
Bandon	Received 6/27/22	http://edocs.puc.state.or.us/efdocs/HAH/ro14hah102112.pdf
Canby Utility Board	Received 6/24/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq84547.pdf
Cascade Locks	Received 4/15/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq103221.pdf
Drain Light & Power	Received 6/21/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq84220.pdf
Eugene Water & Electric Board	Received 7/7/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq1064.pdf
Forest Grove Light & Power	Received 4/13/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq92053.pdf
Hermiston Energy Services	Received 6/28/22	http://edocs.puc.state.or.us/efdocs/HAQ/ro14haq161447.pdf
McMinnville Water & Light	Received 6/7/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq114632.pdf
Milton-Freewater City Light & Power	Received 6/14/22	https://edocs.puc.state.or.us/efdocs/HAH/ro14hah81115.pdf
Monmouth	Received 6/17/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq14935.pdf
Springfield Utility Board	Received 4/15/22	https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq105828.pdf