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
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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.

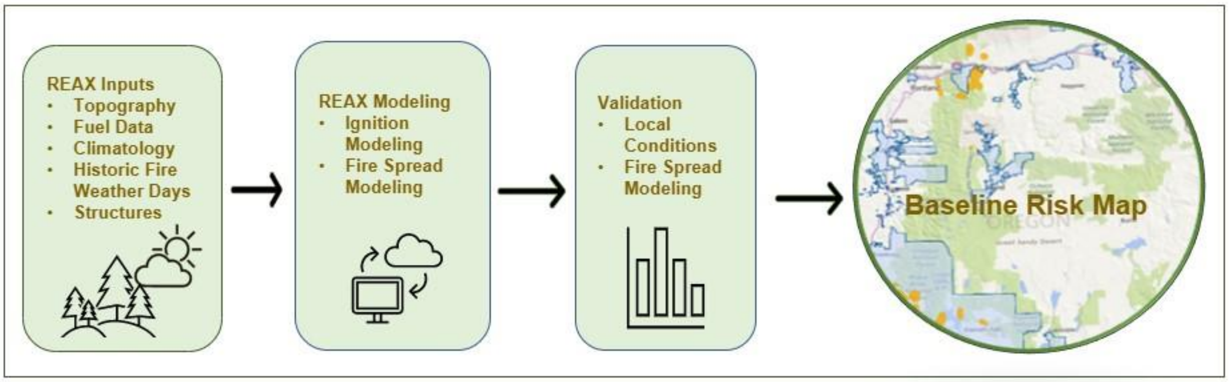


Figure 2: Methodology for Baseline Risk Map

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.

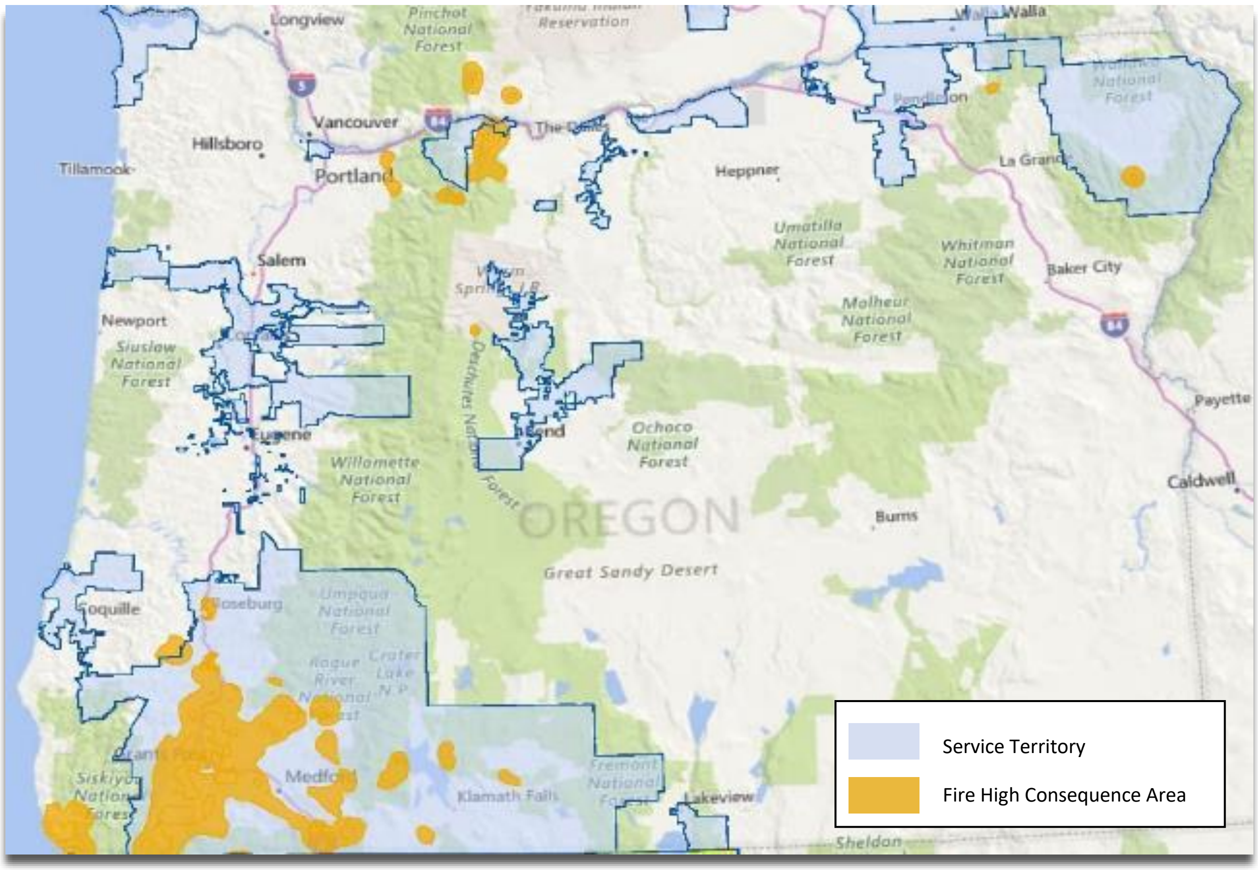


Figure 3: Fire High Consequence Area (FHCA) Map

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.

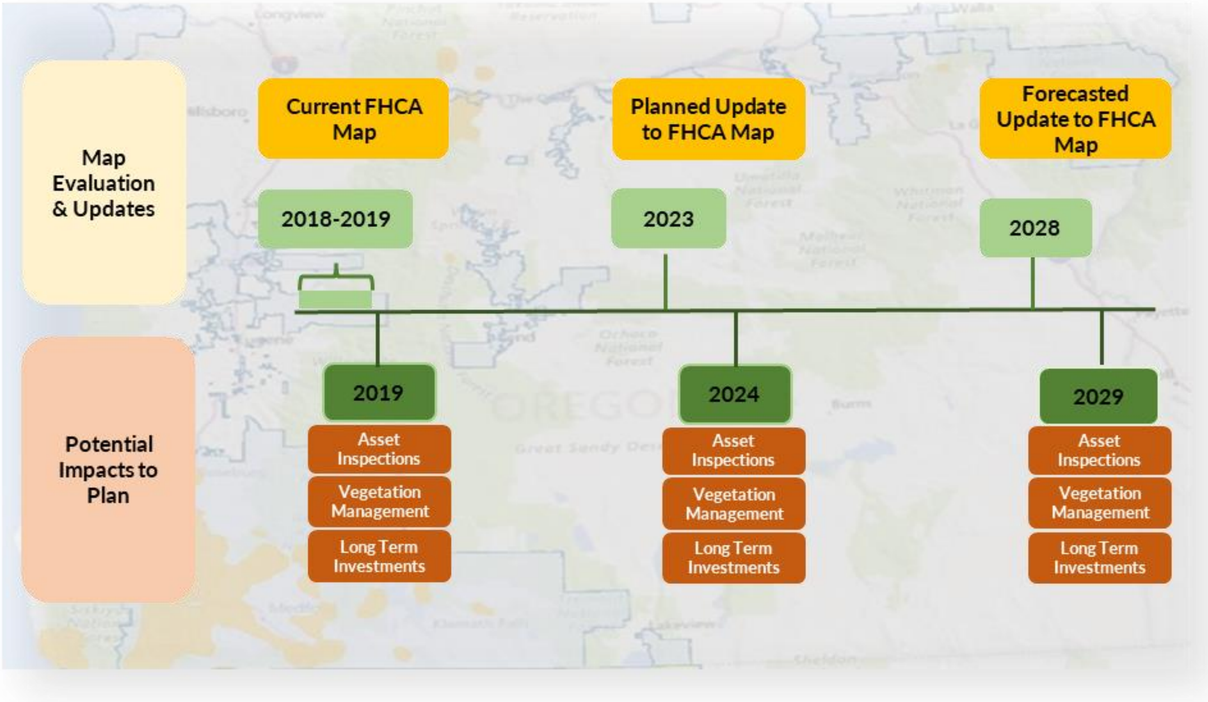


Figure 4: Baseline Risk Assessment Update Frequency

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.

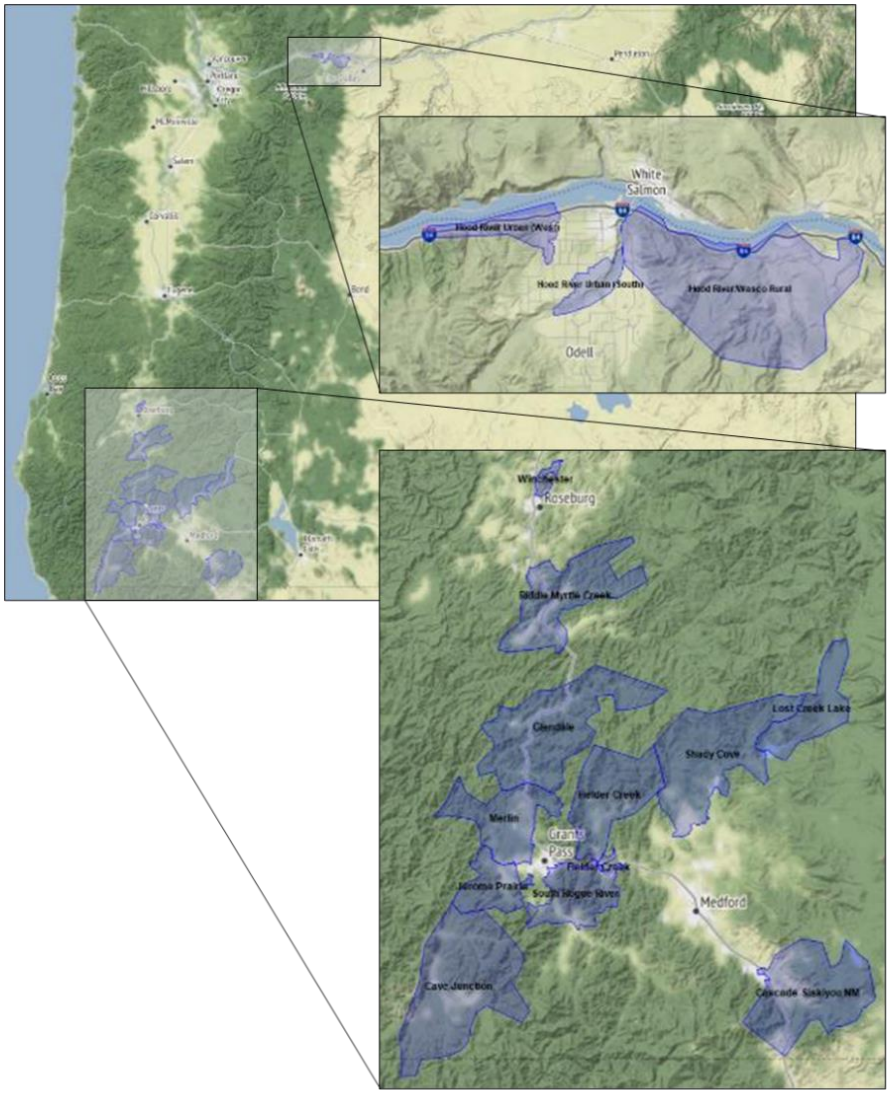


Figure 5: Prioritizes Areas for Long Term Investment

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.

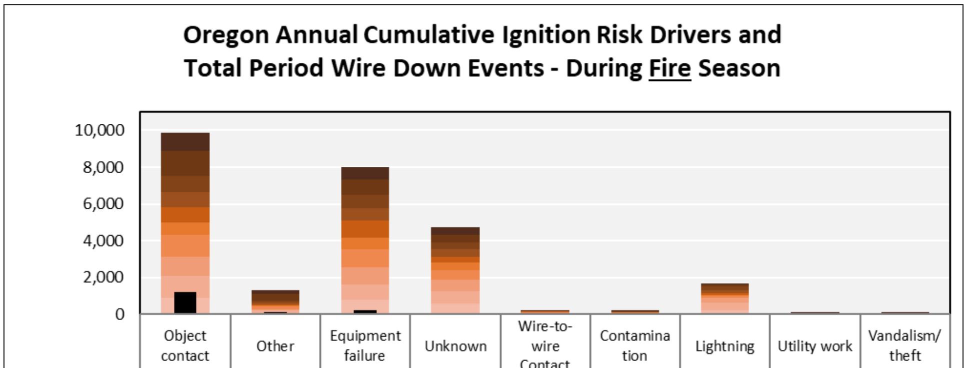
Table 3: Outage Causes with Possible Correlation to Ignition Potential

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

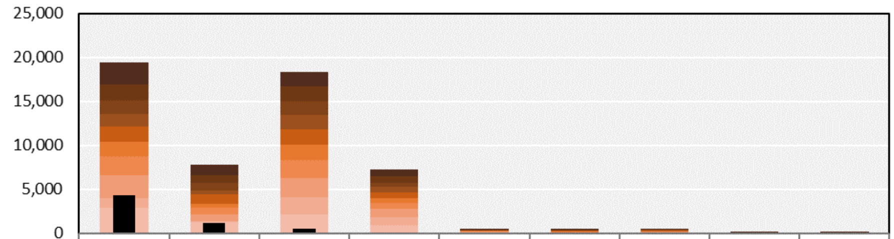
Using these ten outage categories, Pacific Power performed a seven year look back in the outage records and focused specifically on outages occurring during fire season (June 1 through October 1). Because "wire down" events are the situation most likely to ignite ground fuels, tracking and diagnosing 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

Oregon Annual Cumulative Ignition Risk Drivers and Total Period Wire Down Events - During Non-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.

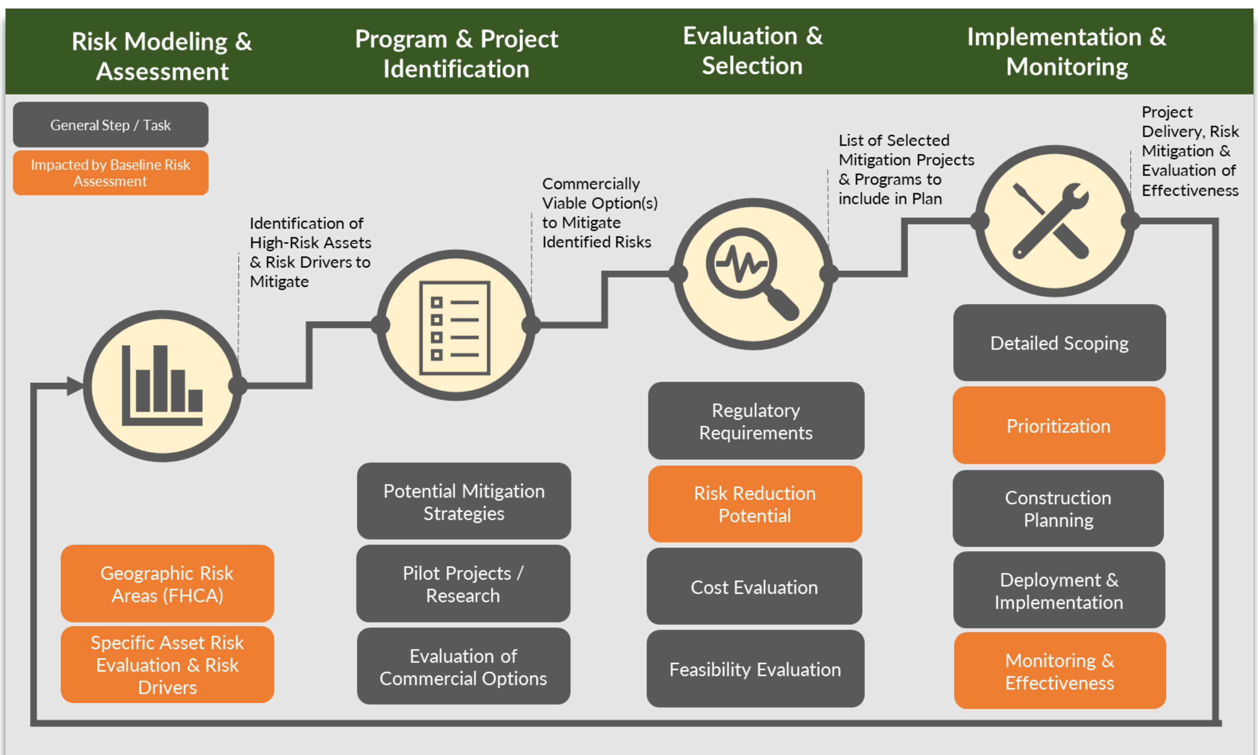


Figure 8: Project and Program Selection High Level Process

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.

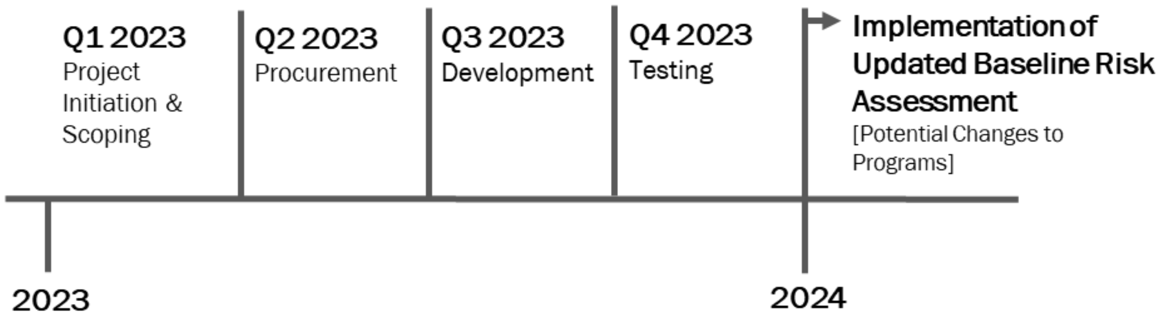


Figure 9: Baseline Risk Mapping (FHCA) Update Timeline

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.

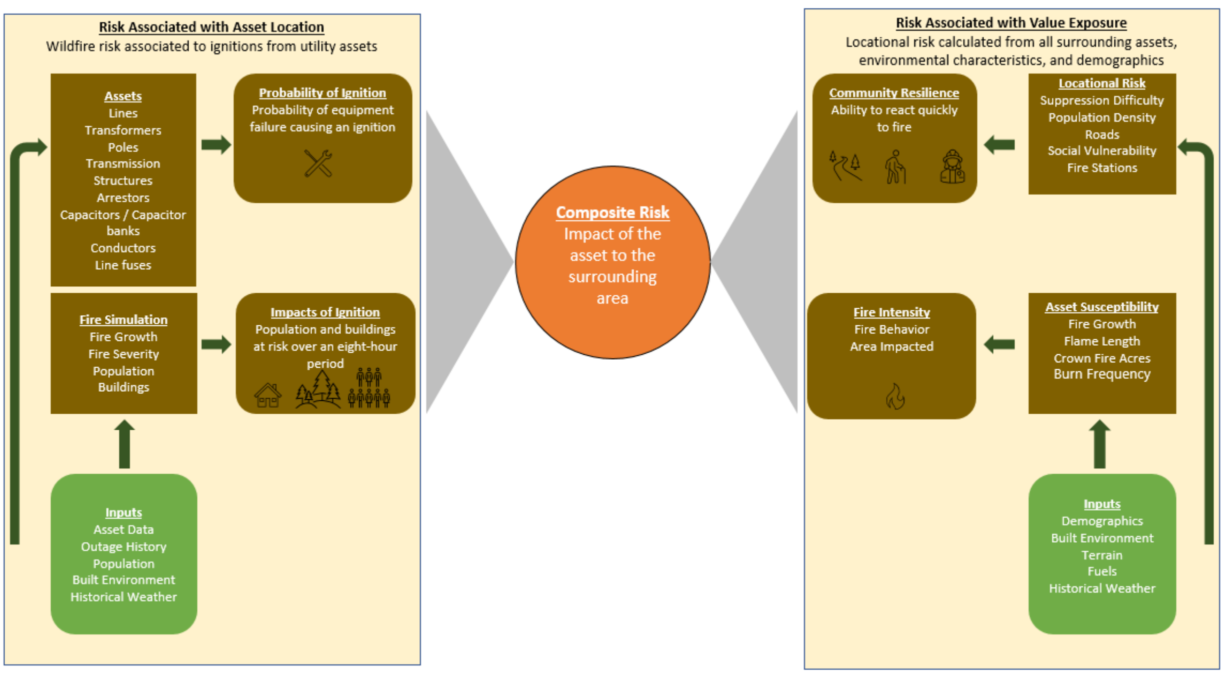


Figure 10: Overall WRRM Framework for Risk Estimates

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.

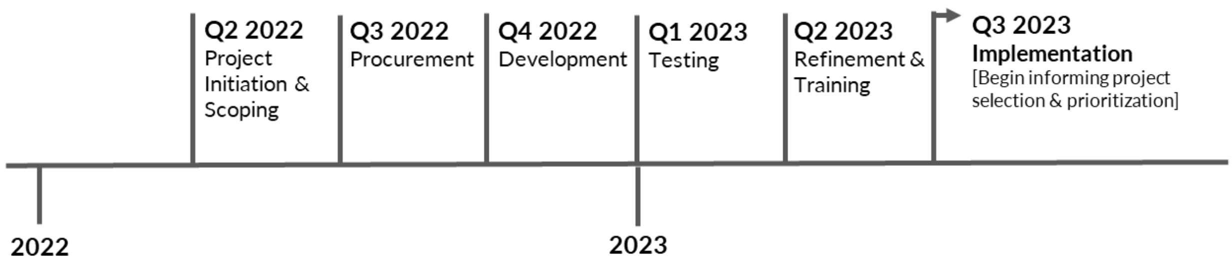


Figure 11: WRRM Implementation Timeline

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.

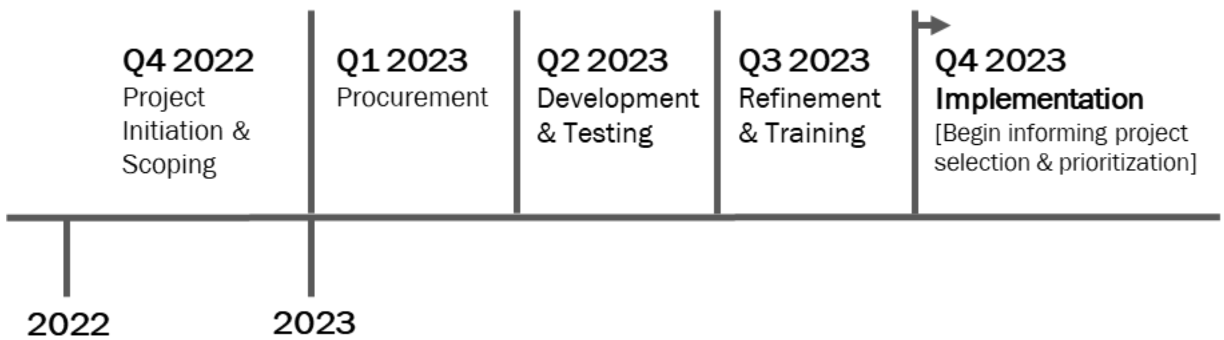


Figure 12: Advanced Data Analytics Project Timeline

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.

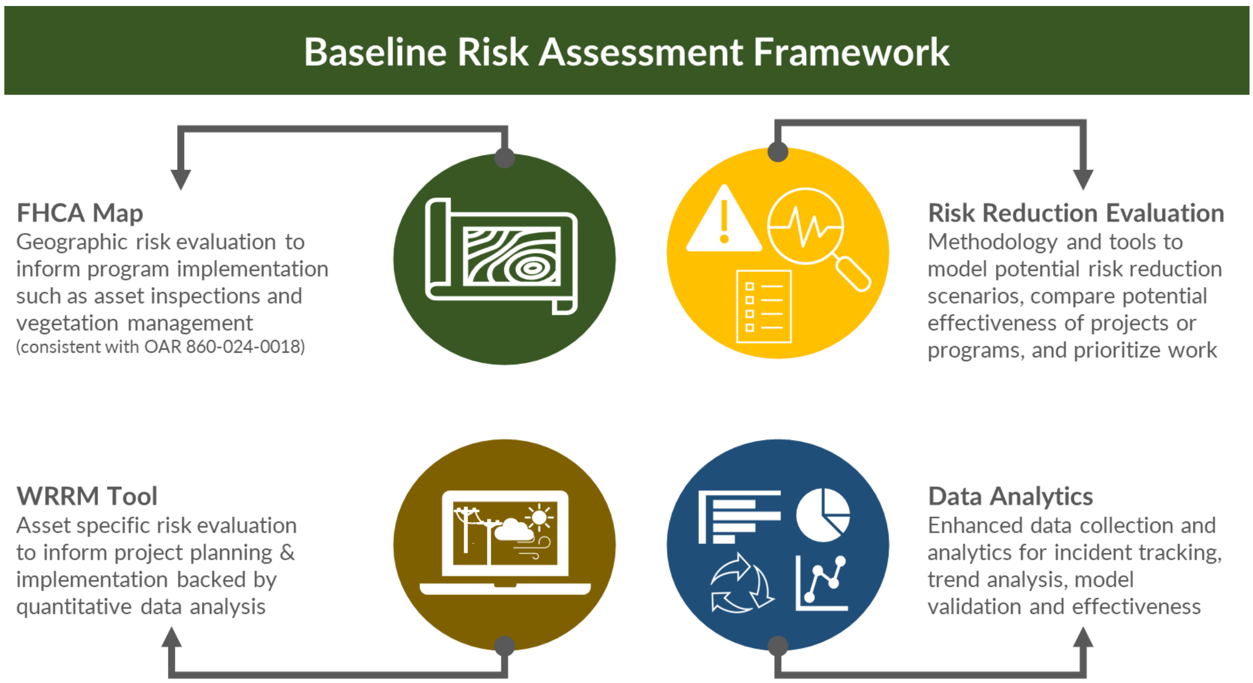


Figure 13: Pacific Power's Future Baseline Risk Assessment Framework

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.

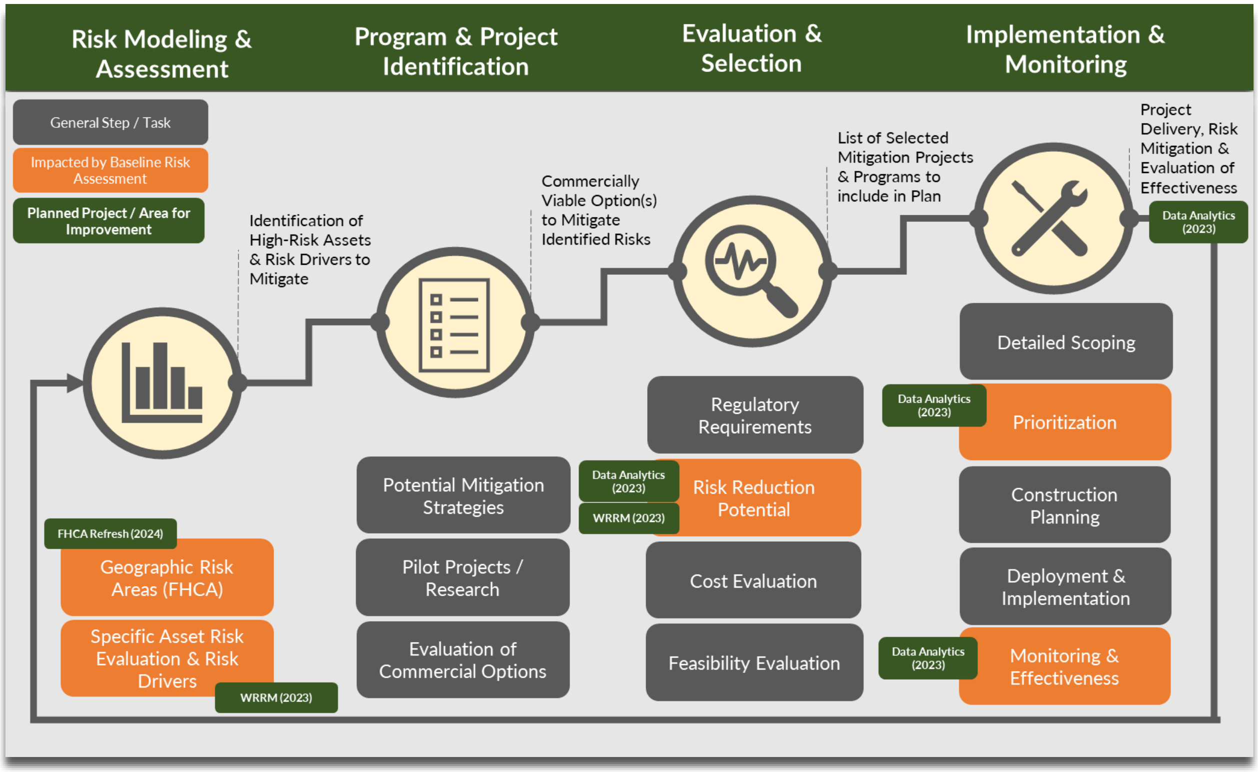


Figure 14: Impacts to Project Selection and Prioritization High Level Process

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.

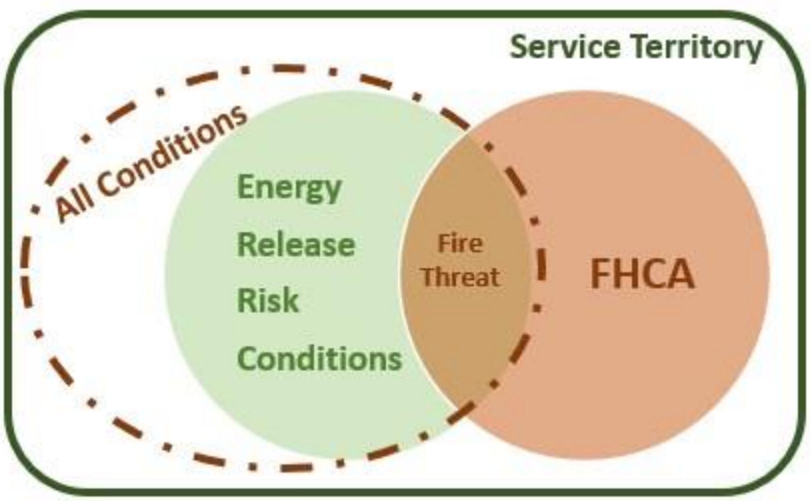


Figure 15: Fire Threat Condition Identification

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.

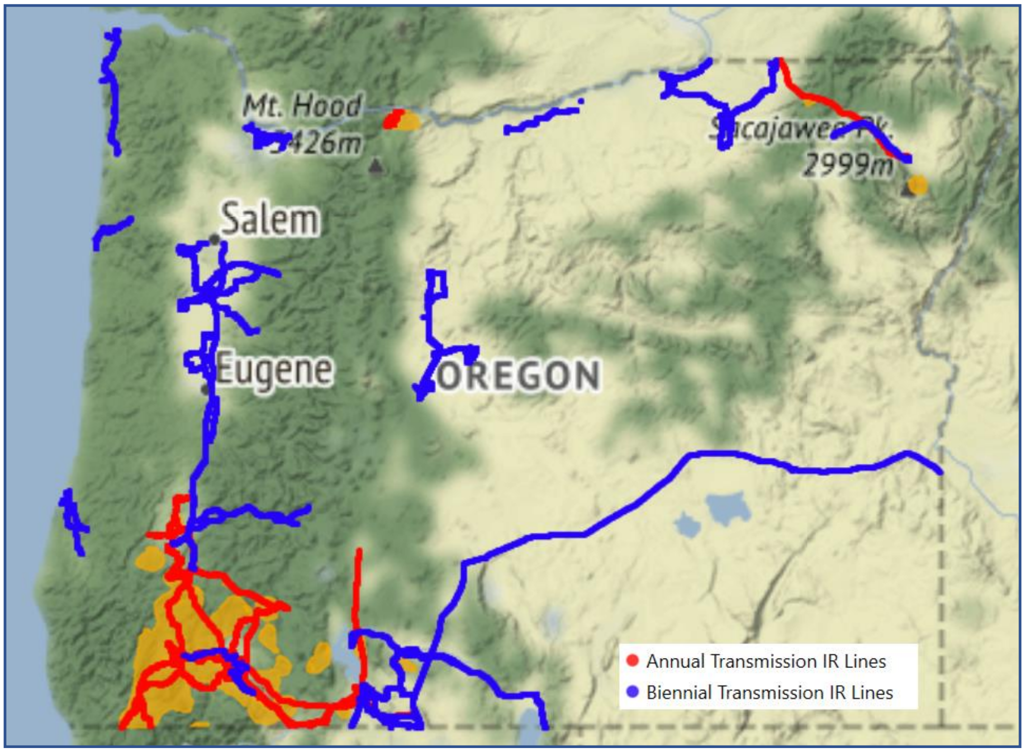


Figure 16: Map of Enhanced Transmission Line Inspections

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.

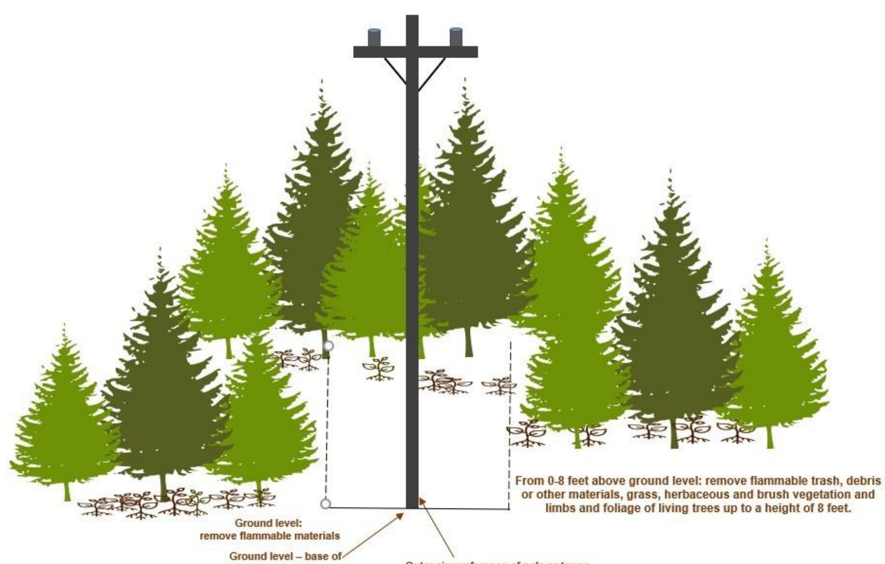


Figure 17: Pole Clearing Strategy

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.

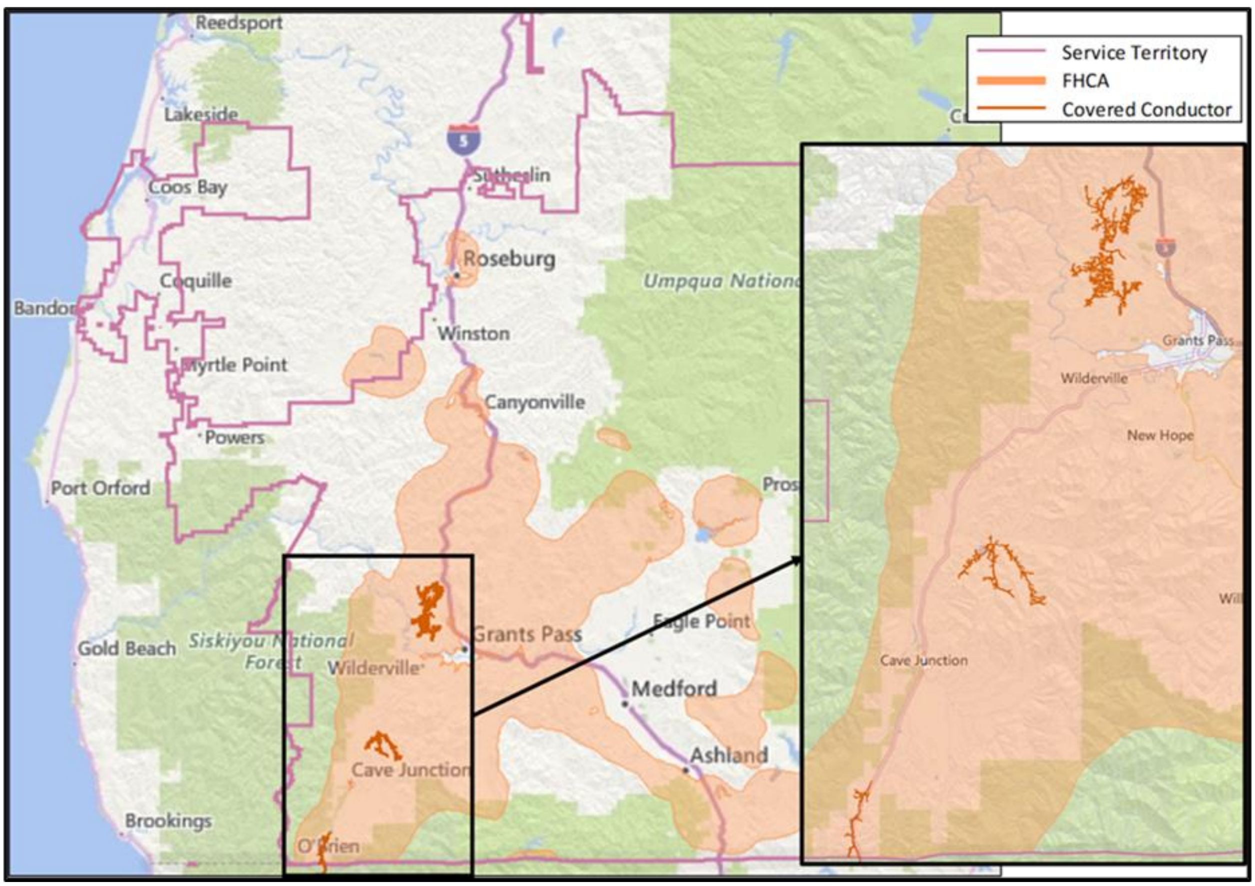


Figure 19: 2022 Completed & 2023 Planned Construction Projects

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.

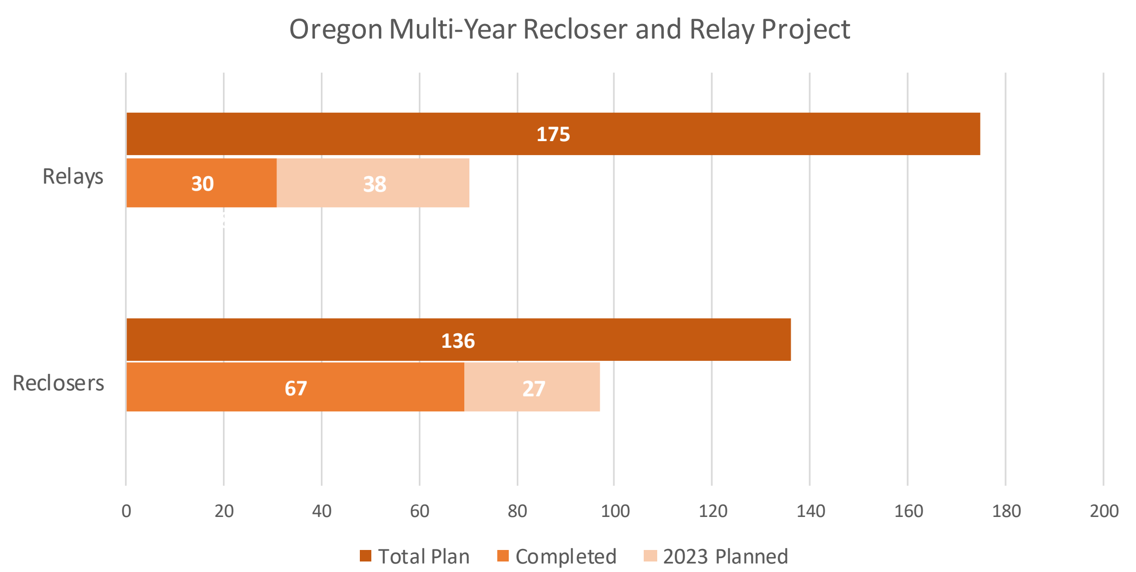


Figure 20: System Automation Project Progress

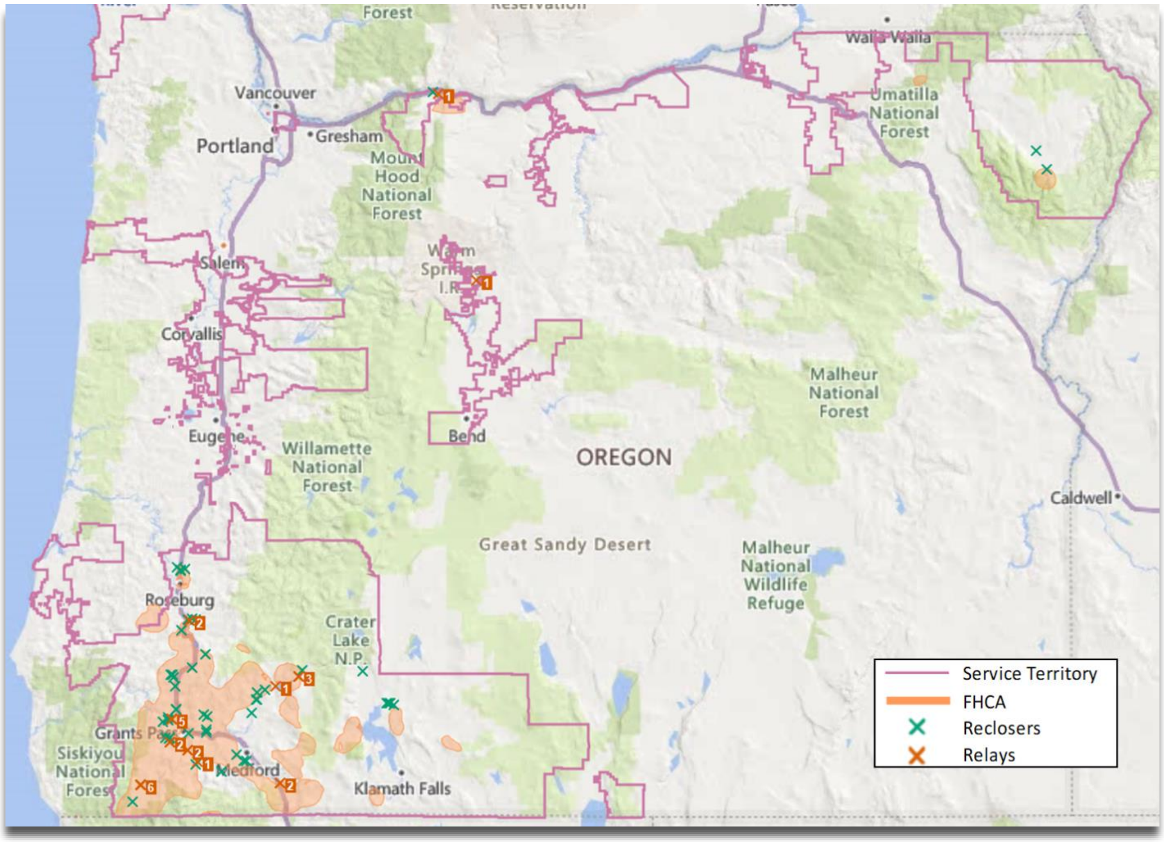


Figure 21: Oregon 2022 Completed Reclosers and Relays Map

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

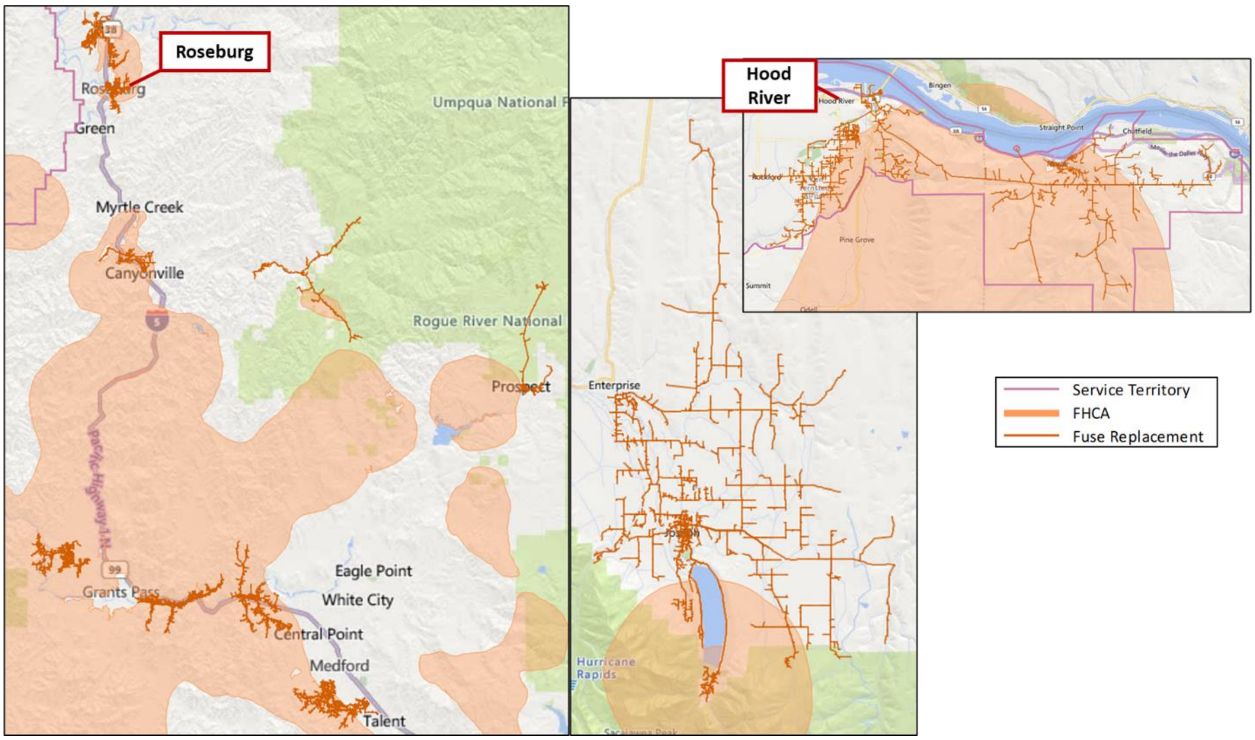


Figure 22: Oregon Expulsion Fuse Replacement Project

[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.

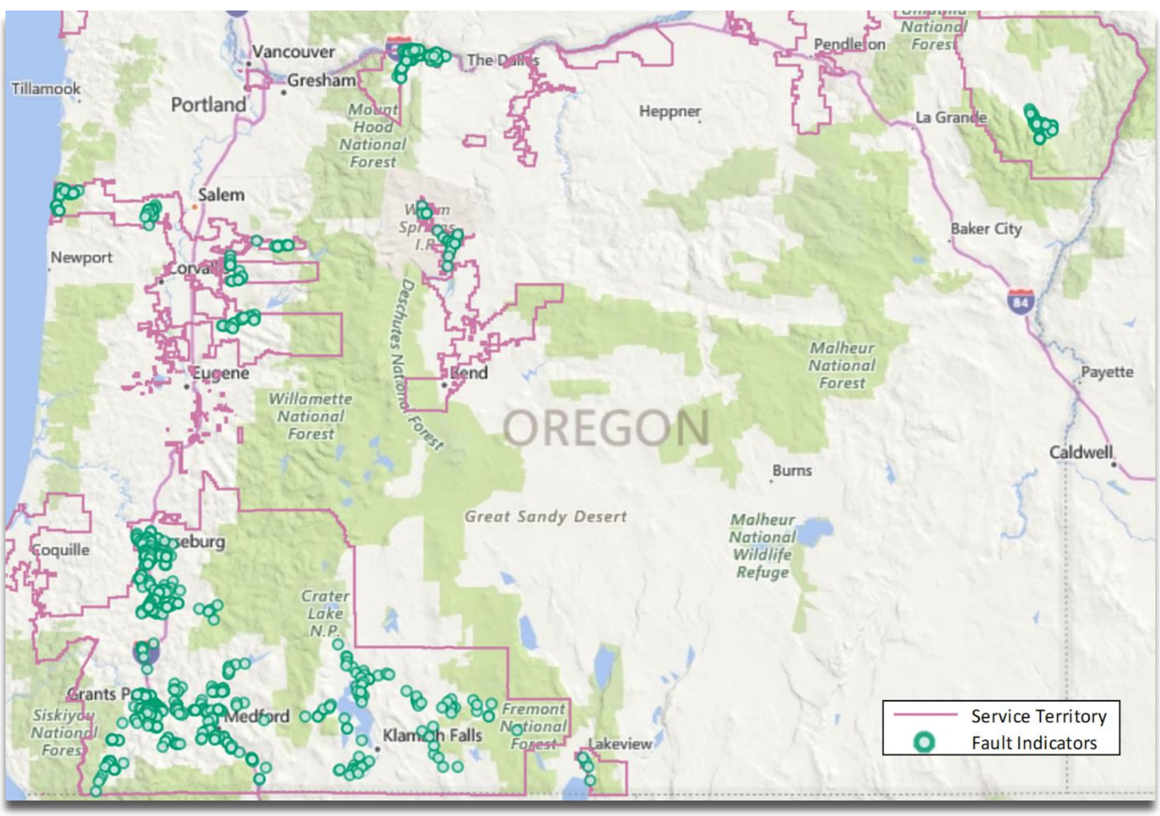


Figure 23: Fault Indicators Installed in 2022

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.

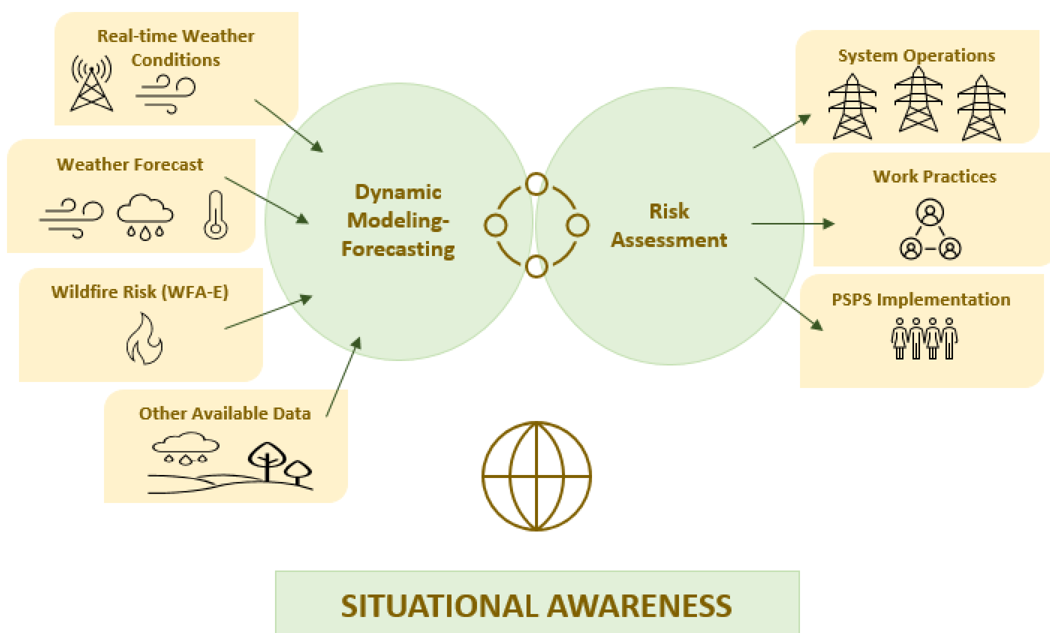


Figure 24: Overview of Situational Awareness

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).

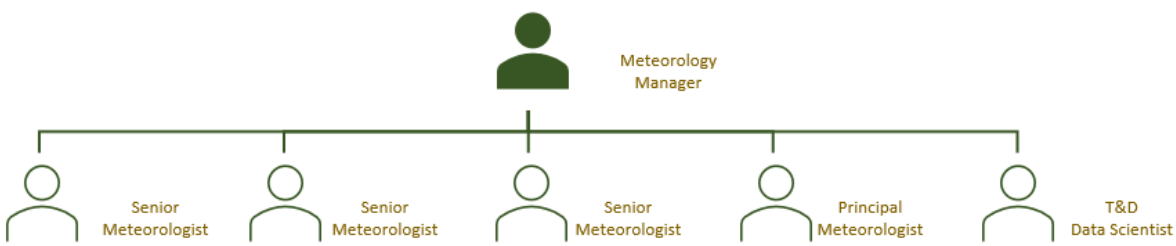


Figure 25: Meteorology Team

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.

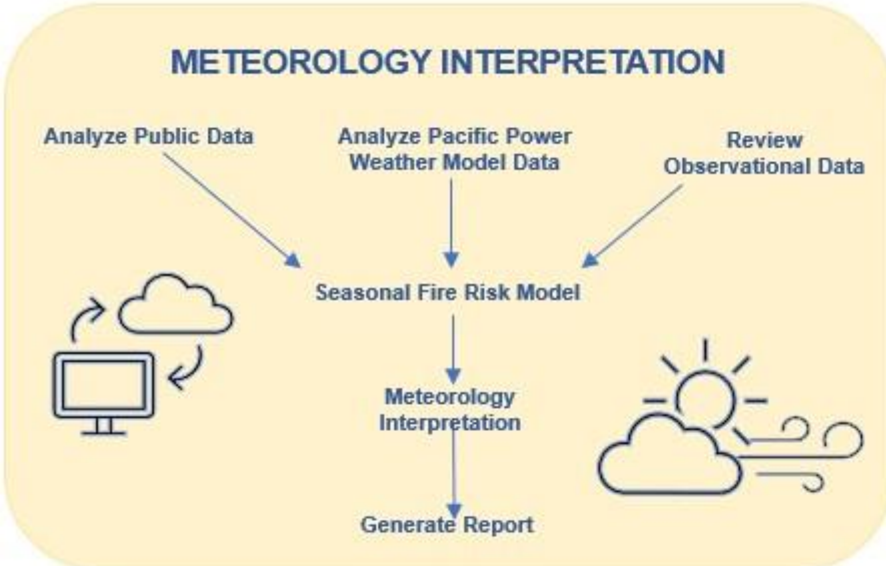


Figure 26: Meteorology Daily Process

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.

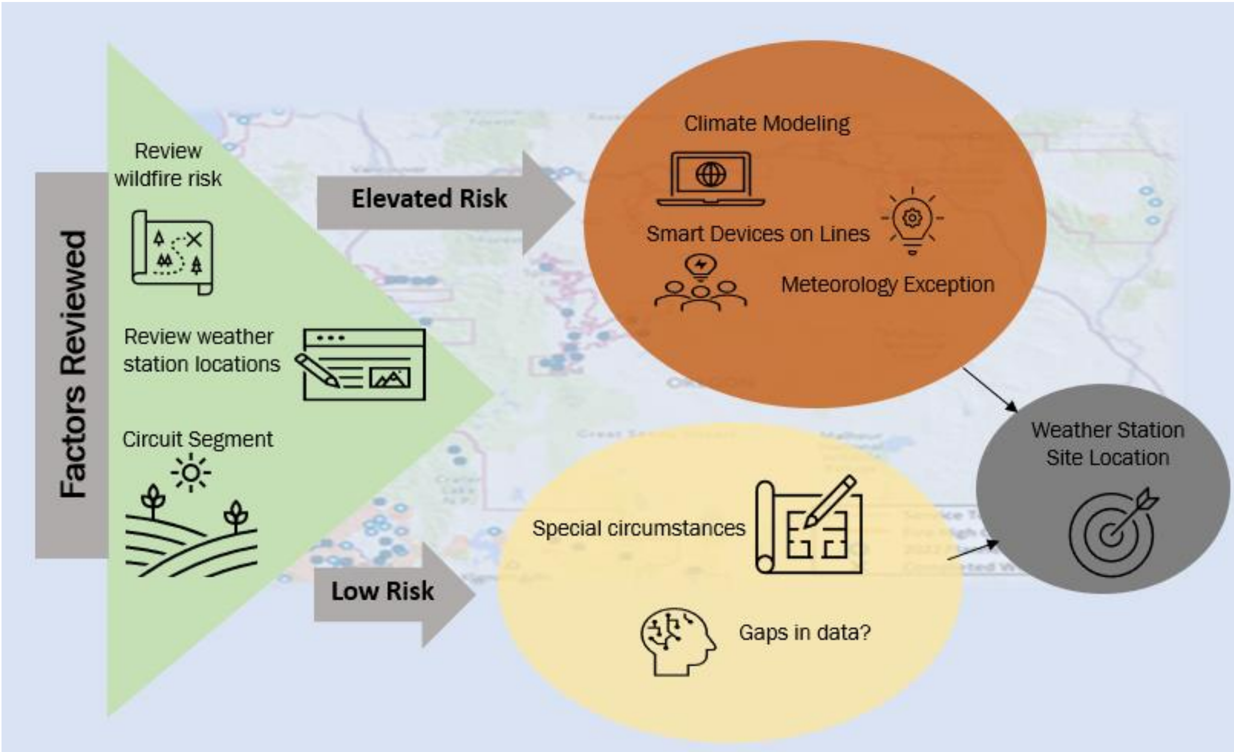


Figure 27: General Weather Station Siting Methodology

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.

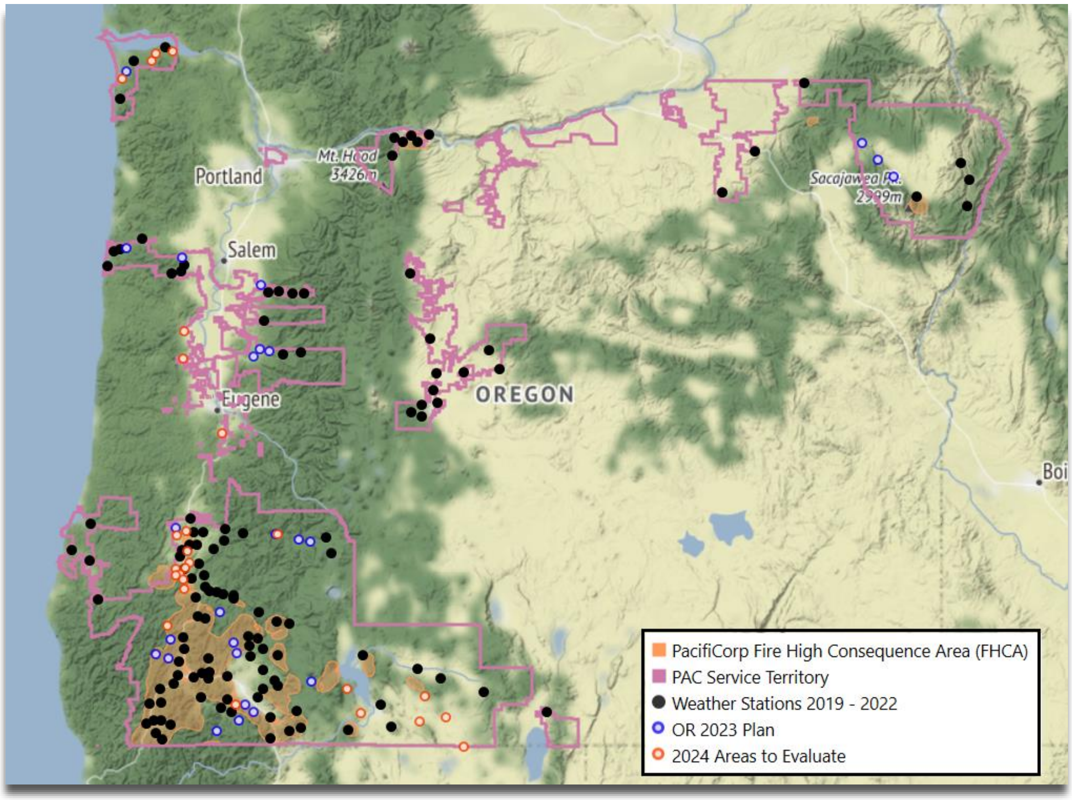


Figure 28: Pacific Power Oregon Weather Station Network (Complete & Planned)

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.

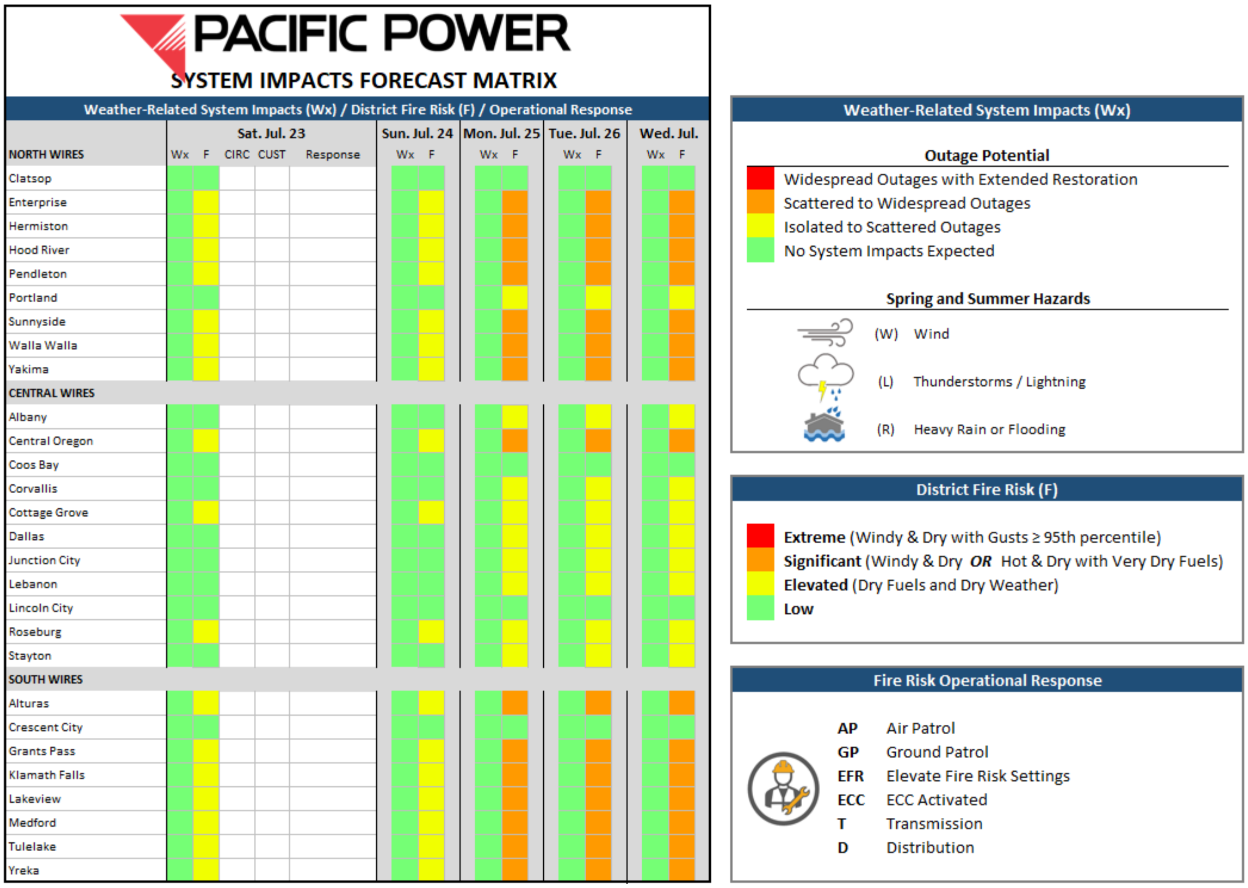


Figure 29: Daily System Impact Forecast Matrix

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.

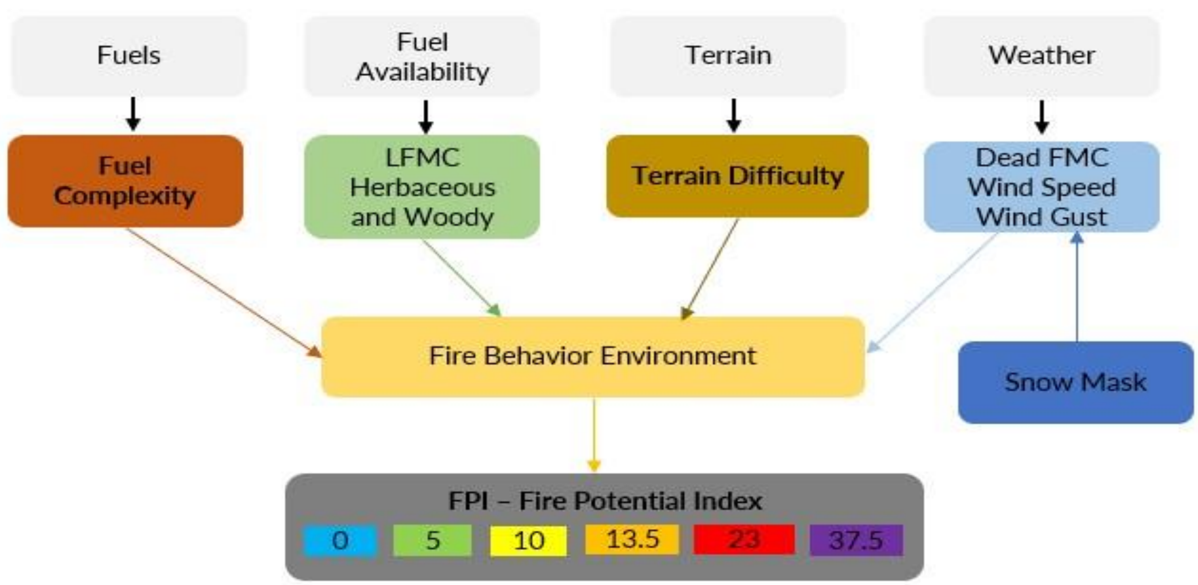


Figure 31: 2023 Fire Potential Index (FPI) Model

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)

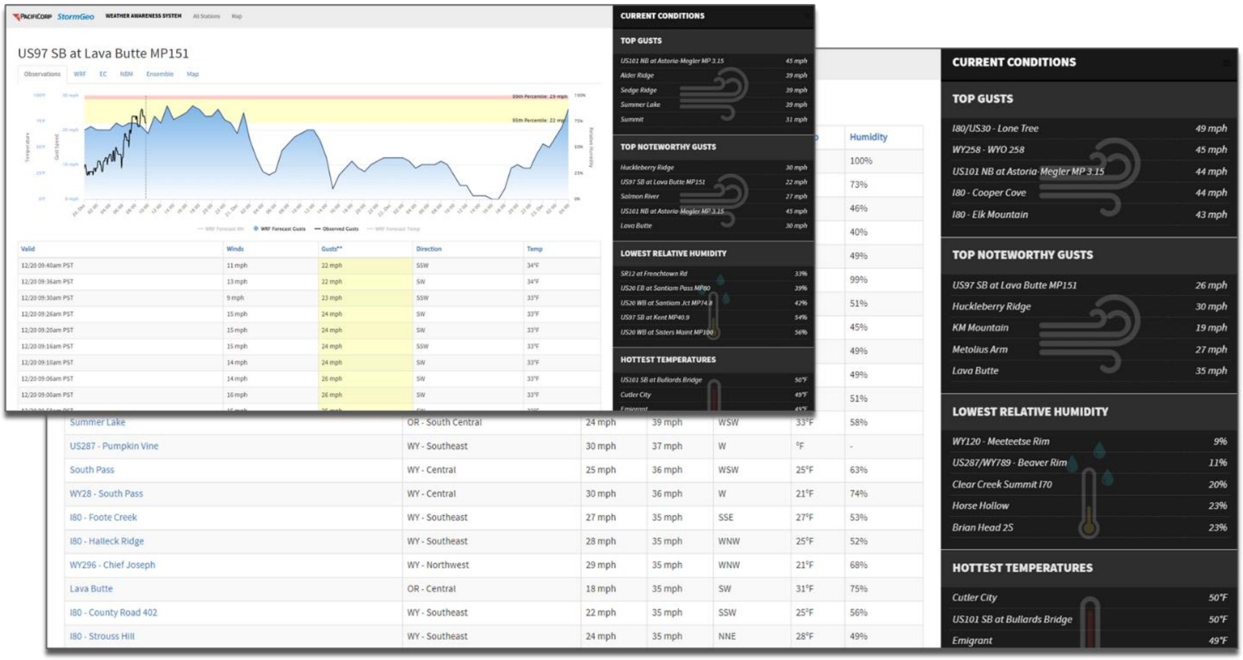


Figure 32: Sample Publicly Available Situational Awareness Information

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.

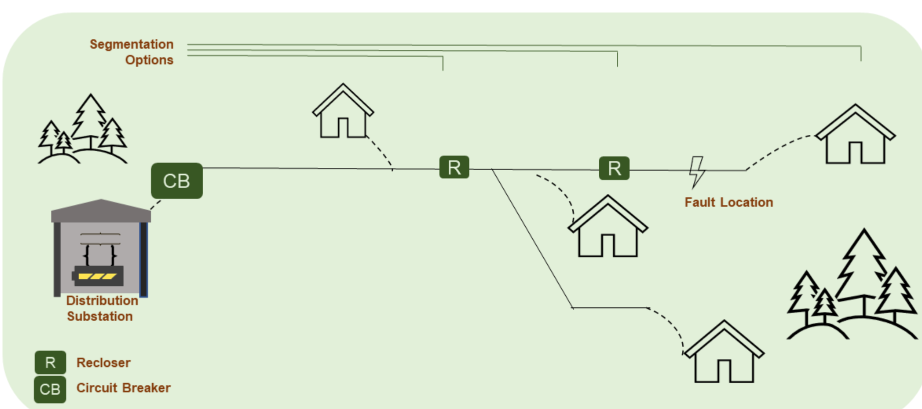


Figure 33: Example of Distribution Circuit with Multiple Reclosers

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.

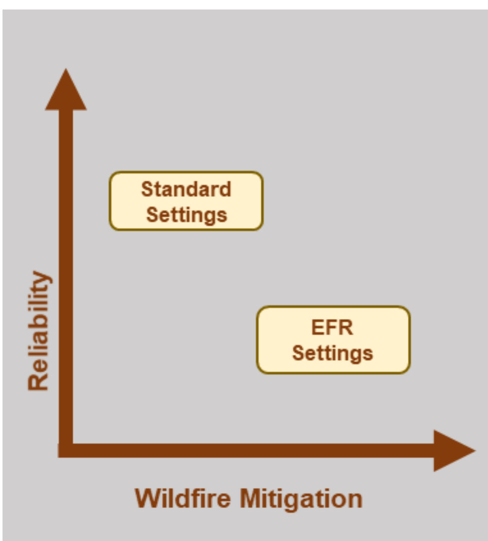


Figure 34: General Relationship between EFR Settings, Reliability, and Wildfire Mitigation

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.

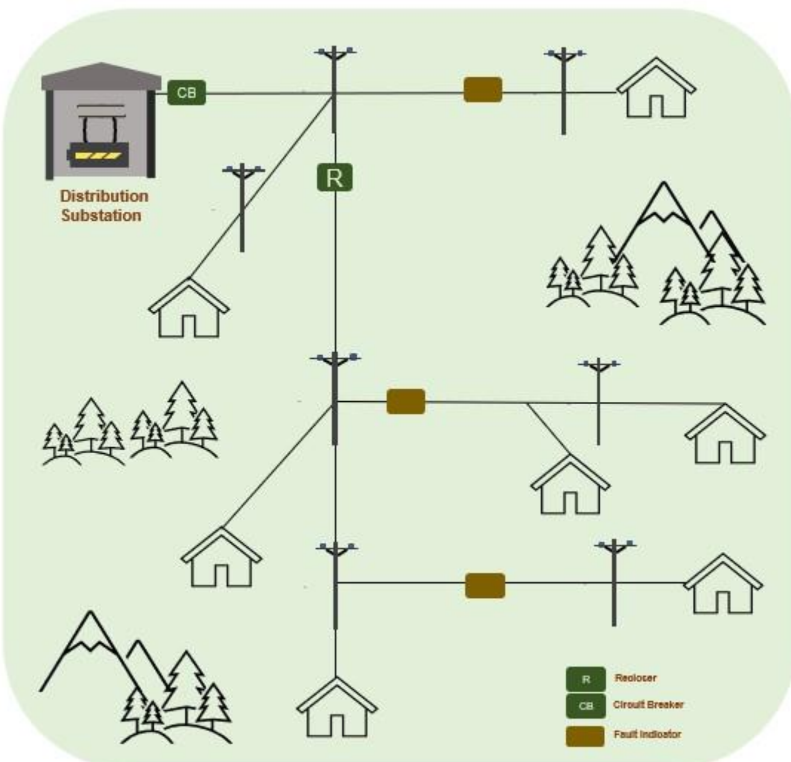


Figure 35: General Fault Indicator Configuration

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.

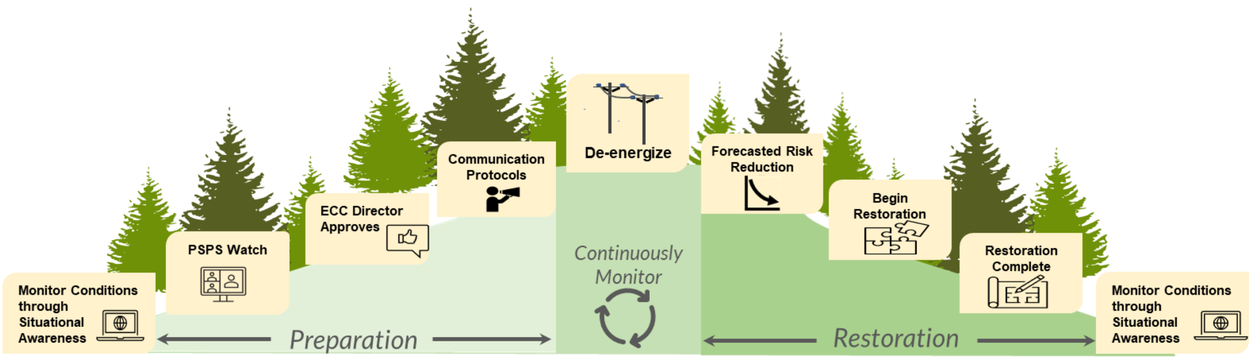


Figure 38: PSPS Overview

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.

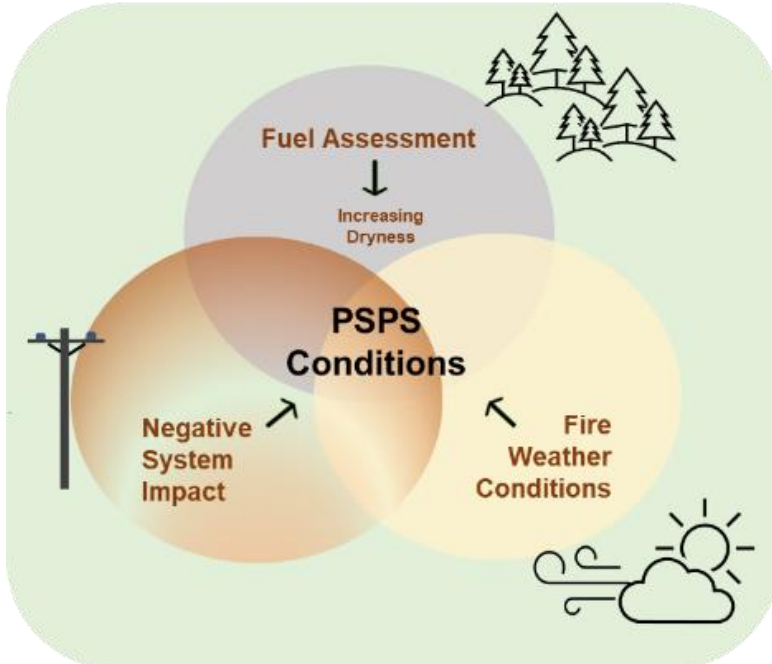


Figure 39: PSPS Assessment Methodology

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.

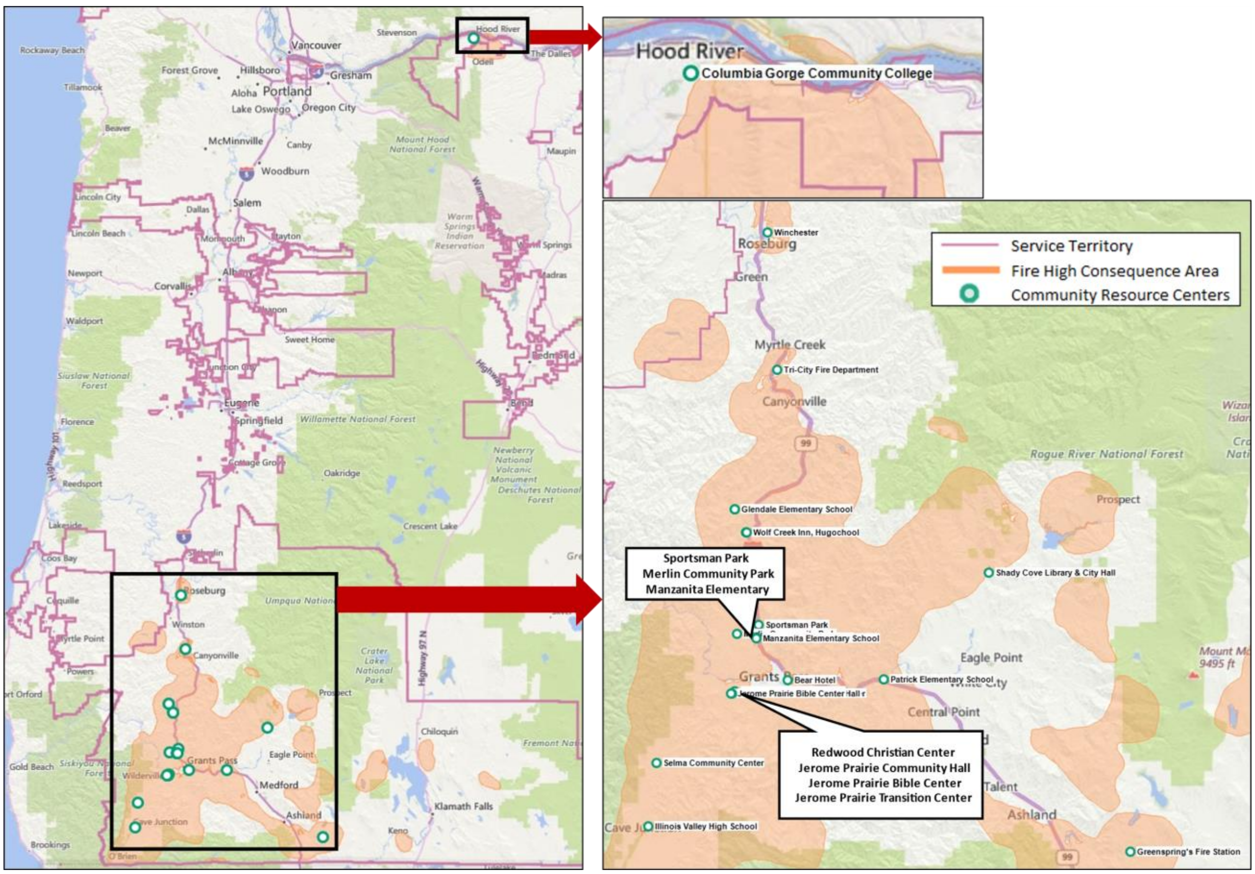


Figure 40: Brick and Mortar CRC Locations in Oregon

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.

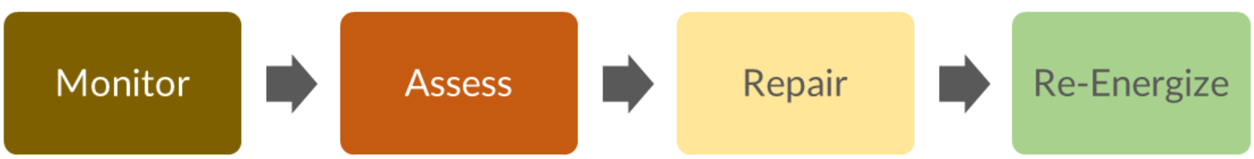


Figure 42: General Re-Energization Process

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.

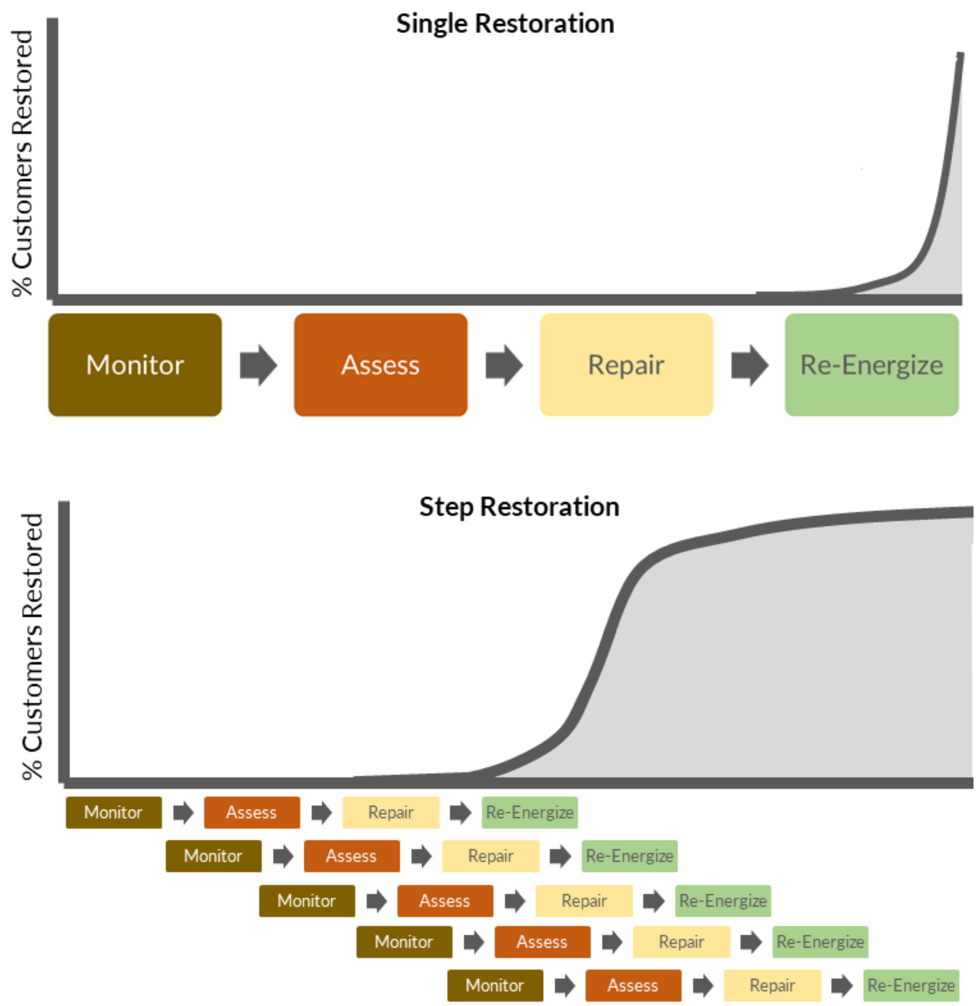


Figure 43: Visual Depiction of Step Restoration

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.

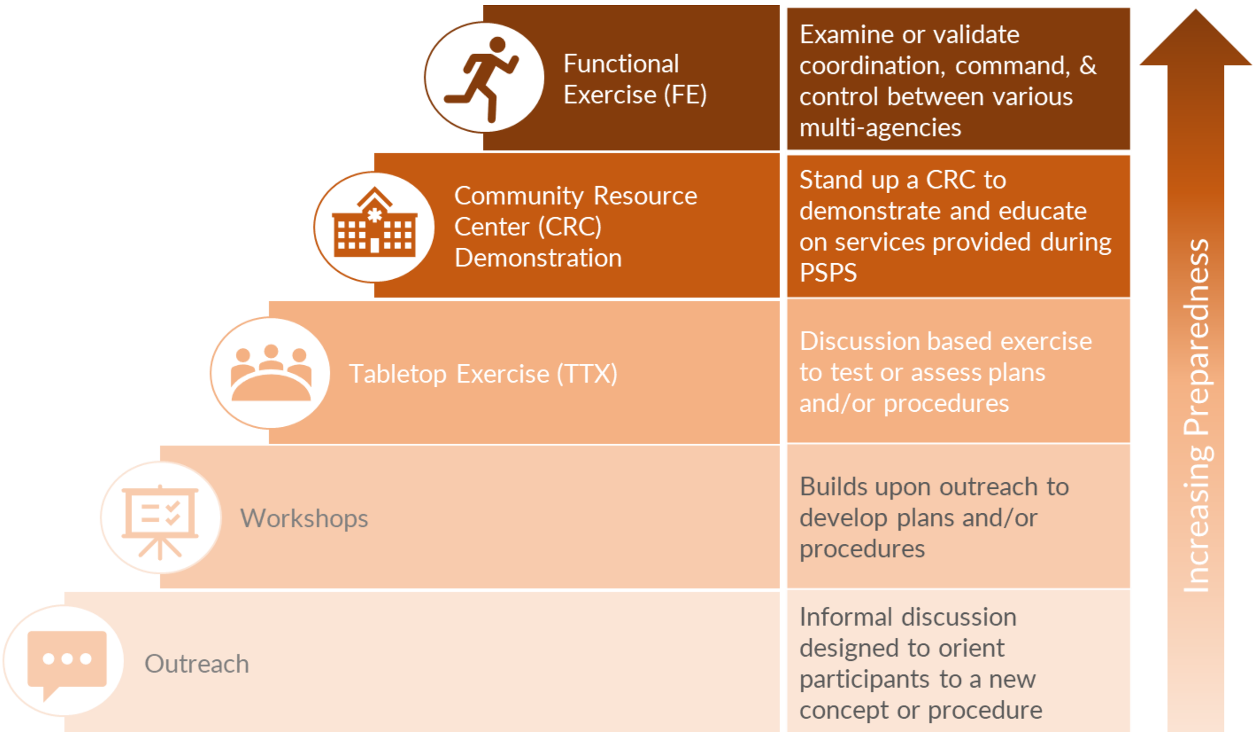


Figure 44: PSPS Preparedness Strategy

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

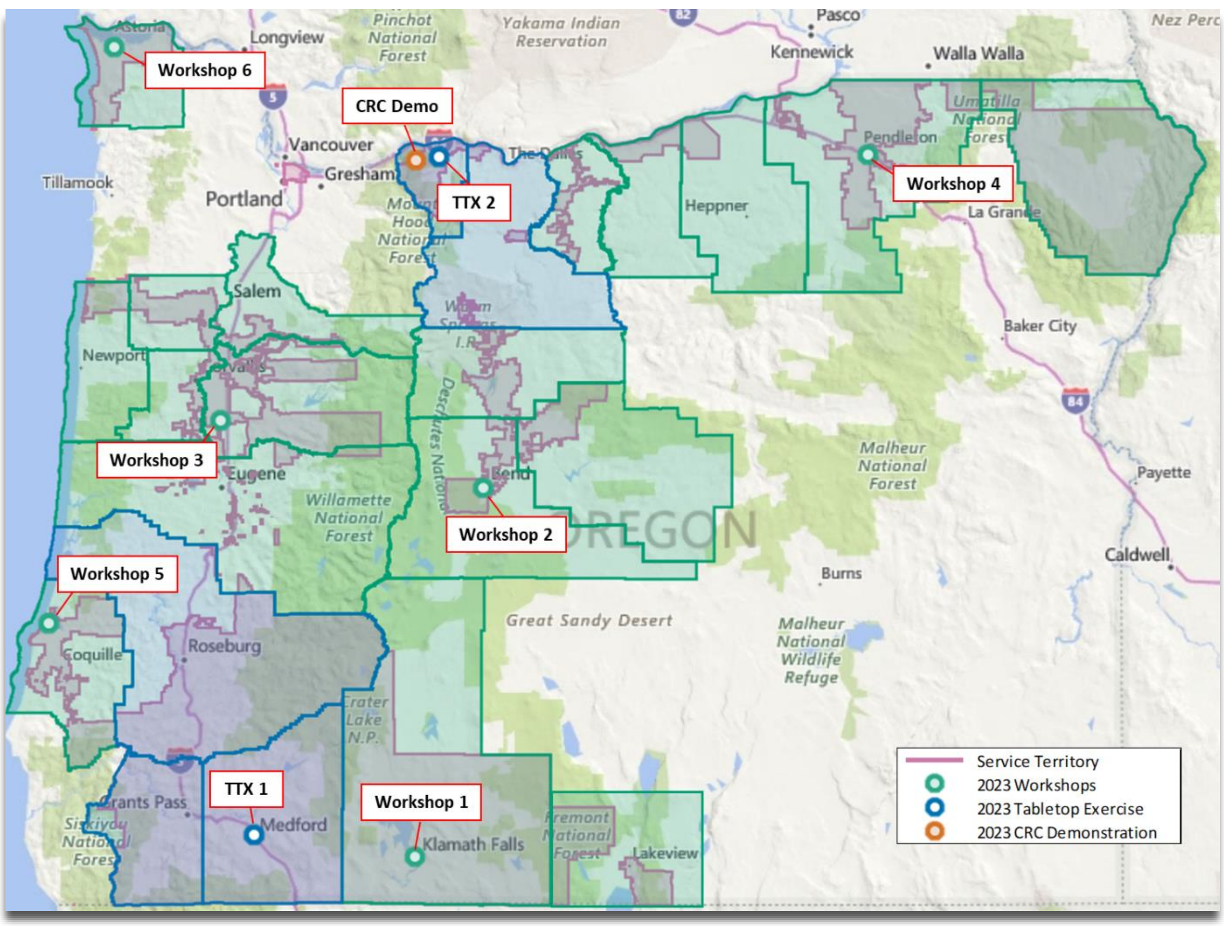


Figure 45: 2023 Emergency Training and Exercise Plan

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.

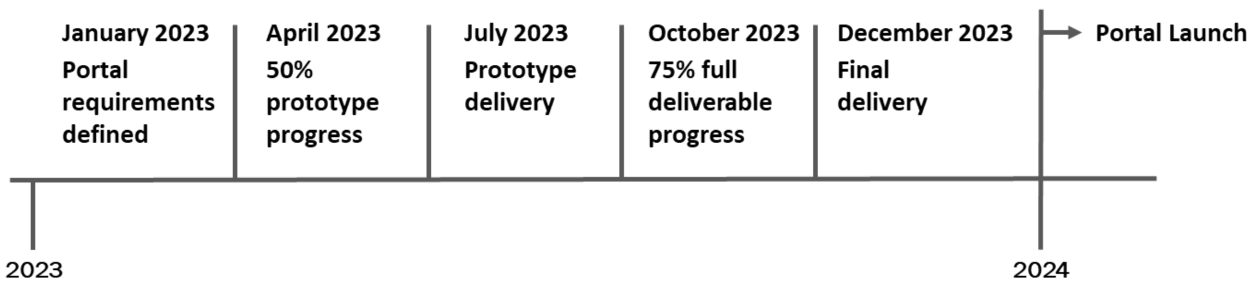


Figure 46: Public Safety Partner Portal Project Timeline

[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.

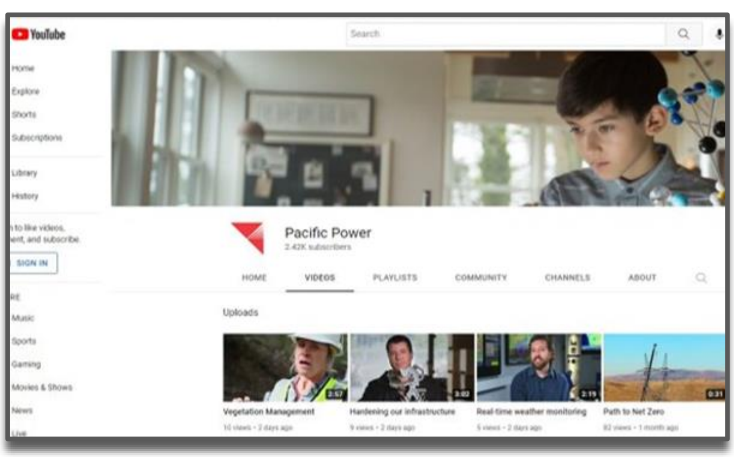


Figure 47: Sample YouTube Material

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.

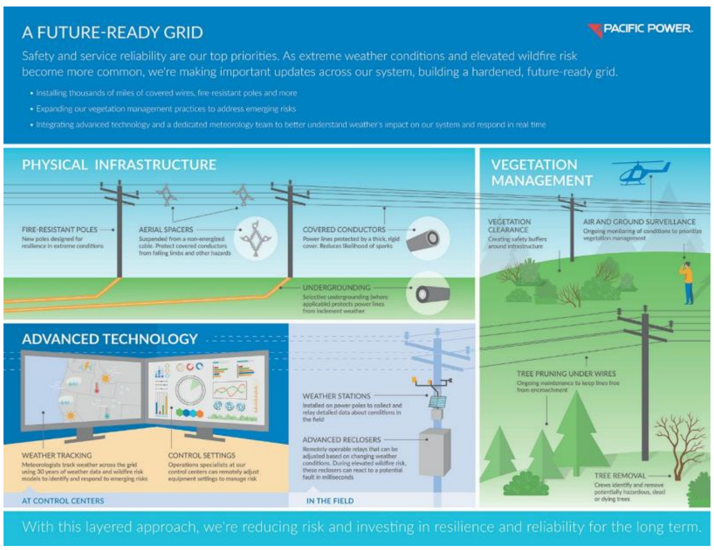


Figure 49: New Wildfire Safety Infographic

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.

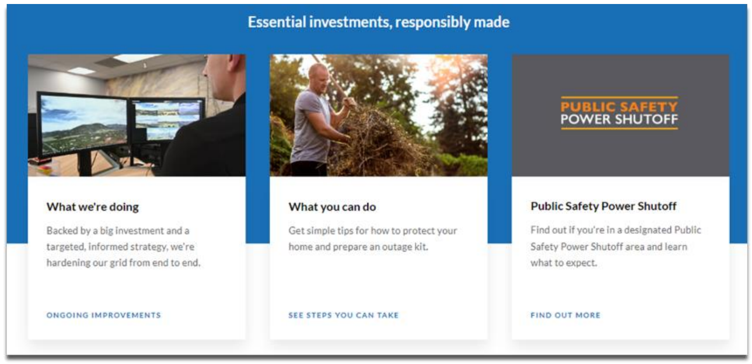


Figure 50: Sample Website Material

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.

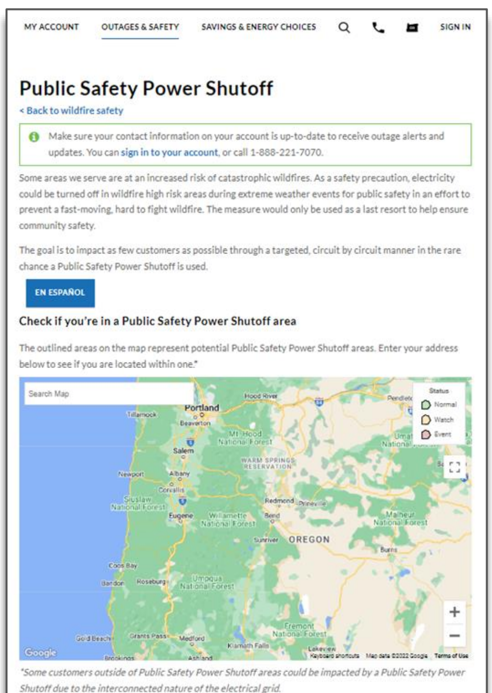


Figure 51: PSPS Interactive Map

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

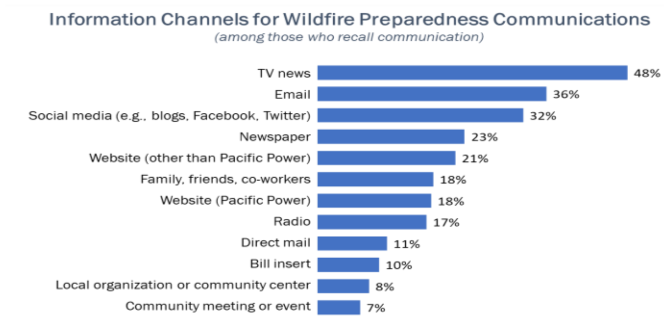
The target audience for the survey included residential, business and critical customers in Oregon. The study was conducted using a mix of online (2,860 completed) and phone (75 completed) surveys. Surveys were available to customers in English and Spanish. A total of 2,935 surveys, including 75 from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

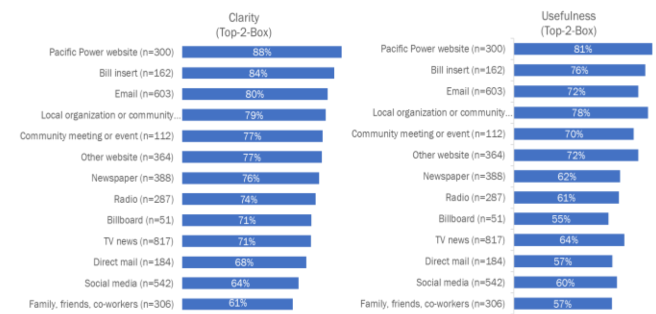
High level findings from the customer and CBO surveys are included below and grouped based on general awareness, PSPS awareness, and PSPS experience.

General Wildfire Safety and Preparedness Messaging Highlights

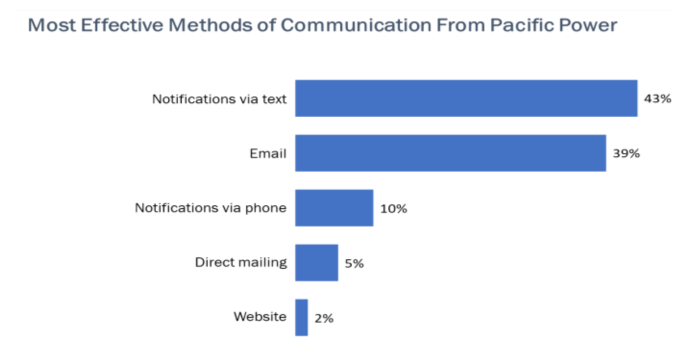
TV News, email and social media were the primary channels recalled for general wildfire preparedness communications.



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



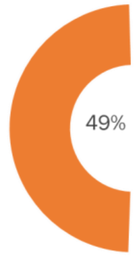
Notifications via text message were considered the most effective communication method **from Pacific Power**, followed closely by email.



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

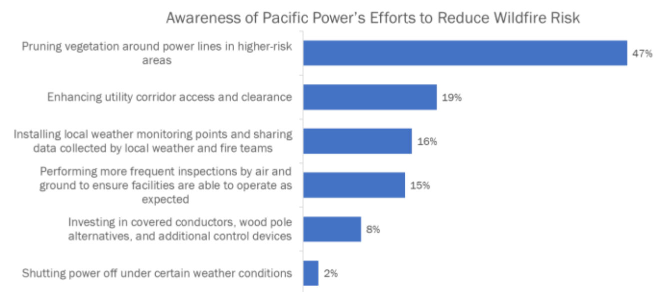
49% of respondents also reported taking action to prevent wildfires or to prepare their home or business for the event of a wildfire.

Took Actions to Prevent or Prepare for a Wildfire



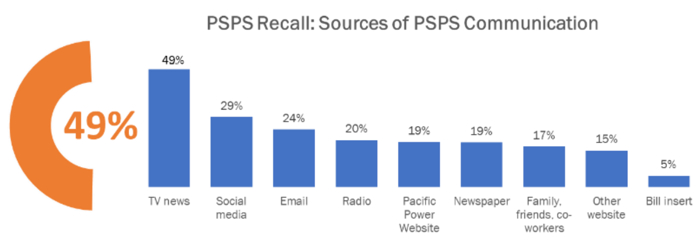
Actions Taken	Total (n=1,442)
Trimmed vegetation around home or property	66%
Created defensible space	23%
Prepared an emergency kit	14%
Watering/installed watering systems	14%
Prepared an emergency readiness plan and contact information	9%

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.

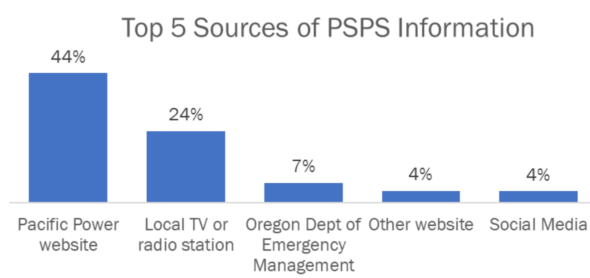


PSPS Messaging and Awareness

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.**



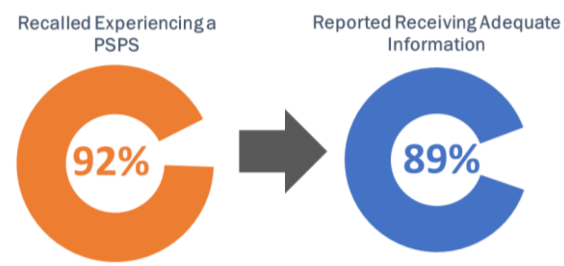
80% reported understanding that "for areas at a higher risk of fast-spreading catastrophic wildfires, **the utility will proactively shut off power during extreme and dangerous weather."**

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

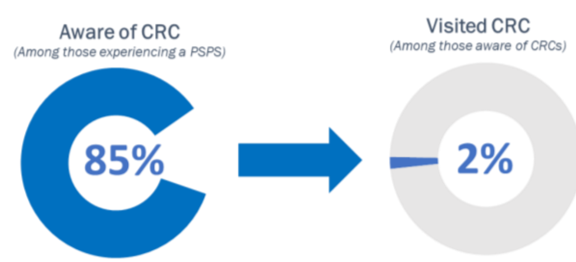
Among customers who experienced a PSPS, **92% recalled the event** and **89% reporting receiving adequate information.**



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.

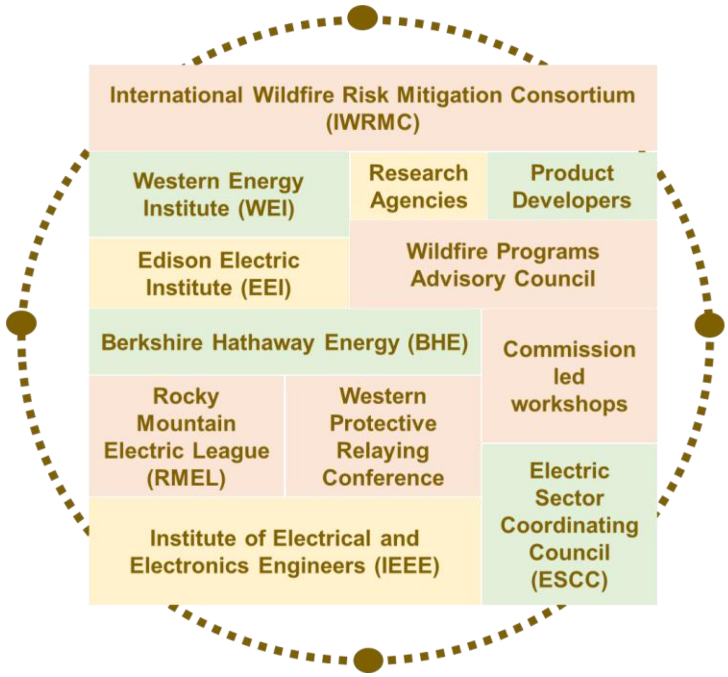


Figure 54: Key Industry Collaboration Channels

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.

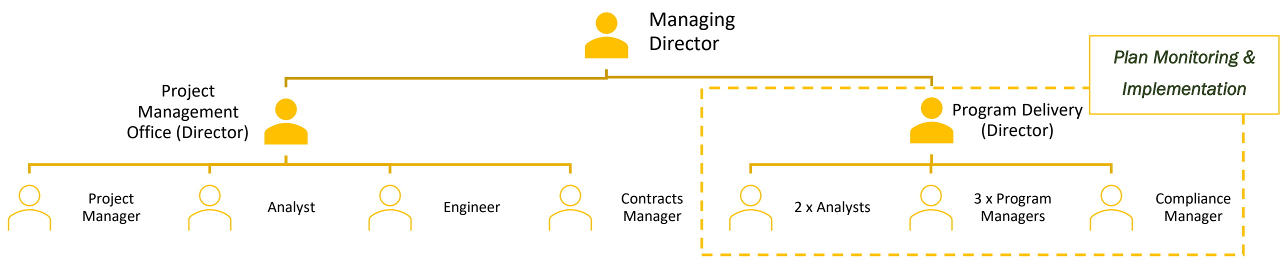


Figure 55: Pacific Power's Wildfire Safety Department

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.

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[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

[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

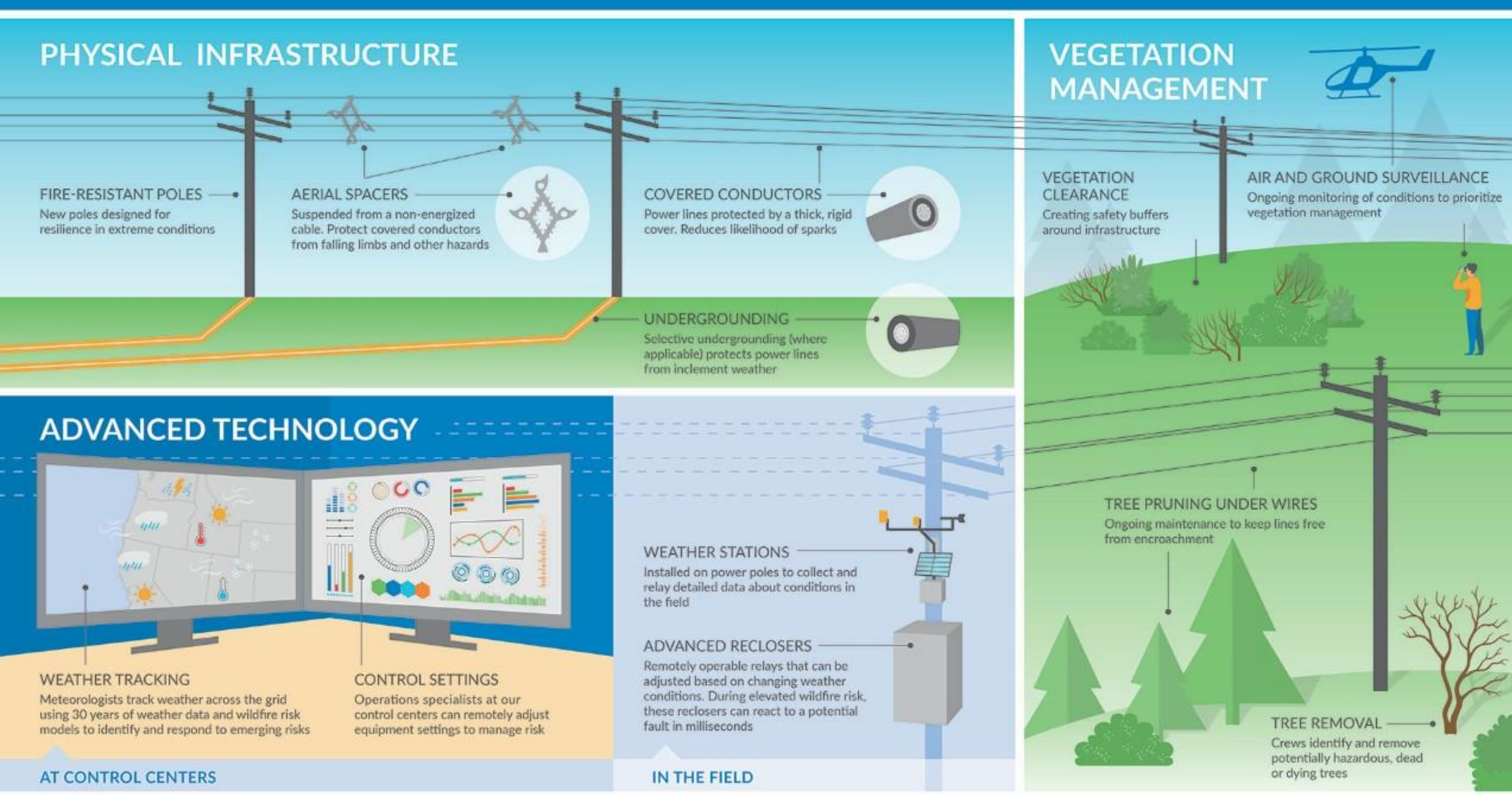
POWERING YOUR GREATNESS

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.