PACIFIC POWER

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Washington Wildfire Mitigation Plan

Pre-Rulemaking Draft

November 16, 2023

Contents

Introduction

Due to the growing threat of catastrophic wildfire in the western United States, Pacific Power has developed a comprehensive plan for wildfire mitigation efforts in all of its service territories. This plan specifically guides the mitigation strategies that will be deployed in Washington. These efforts are designed to reduce the probability of utility related wildfires, as well 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. Decades of disturbing trends in 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, has catastrophic consequences on people and property.

The relationship between wildfire and public utilities has been brought to the fore by recent developments in California. The loss of human life and property damage in 2017 and 2018 highlighted that wildfire is not constrained to southern California, whether associated with electric utilities or not. Wildfire risk in other states, including Washington, cannot be ignored. The general trend toward larger and more destructive fires is not unique to California, but has been recognized, for several decades, in the western United States. In 2018, for example, multiple western states had wildfires exceeding 100,000 acres, including Washington (Klondike Fire and Boxcar Fire), Nevada (Martin Fire and Sugarloaf Fire), and Utah (Pole Creek Fire). Accordingly, Pacific Power is committed to making long-term investments to reduce the chances of catastrophic wildfire.

The measures in this Wildfire Mitigation Plan (WMP) describe those investments to construct, maintain and operate electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire. In evaluating 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 Washington customers and Washington communities, in the overall imperative to provide safe, reliable, and affordable electric service.

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.

Plan Activity

The following table presents a summary of the planned mitigation activities and the planned timeframe for implementation.

Table 1: System Hardening 2020- 2023 Summary

Mitigation Program	**Total Units**	**2020**	**2021**	**2022**	**2023**
System Hardening: Installation of Covered Conductor (miles)[1]	6	0	0	0	10
System Hardening: Distribution Pole Replacement	168	0	0	0	220
System Hardening: Distribution Relays	2	0	0	1	1
System Hardening: Distribution Recloser	6	0	0	5	1
Situational Awareness: Weather Stations [2]	18	3	0	3	12

Table 2: Incremental Planned Spend (in millions) Per Mitigation Program

Mitigation Program	Type of Expenditure	Total	2020	2021	2022	2023
System Hardening: Installation of Covered Conductor, Pole Replacements, Reclosers, Relays	Capital	$12.86	$0.19	$0.43	$6.22	$6.00
Situational Awareness: Weather Stations	Capital	$0.16	$0.05	$0	$0.11	$0
Vegetation Management	Expense	$0.58	$0	$0	$0.29	$0.29
Asset Inspections, IR Inspections, Stakeholder and Community Engagement, Plan Monitoring	Expense	$0.27	$0	$0.09	$0.09	$0.09
Total	Mixed	$13.87	$0.24	$0.52	$6.71	$6.68

[1] Covered conductor line miles will be installed during both 2022 and 2023 as part of one, complex project. The line miles completed in 2022 is dependent on the approval of the required permits and yet unknown limits on construction dates due to protected plants and wildlife. Based on this all line miles are forecast for 2023 completion.
[2] 2020 weather station units include one weather station installed in late 2019.

1. Risk Analysis and Drivers

1.1 Methodology for Identifying and Evaluating Risk

This risk evaluation process employs the concept that the risk is essentially the product of the likelihood of a specific risk event multiplied by the event's impact. 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 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 of harm to people and damage to property.

1.1.1 Modeling Pacific Power's Wildfire Risk

A disruption of normal operations on the electrical network, called a "fault" in the industry, could be a possible ignition source for wildfire. Under certain weather conditions and near wildland fuels, an ignition can grow into a harmful wildfire, potentially even a catastrophic fire, causing great harm to people and property. This general relationship is shown in the Venn diagram below.

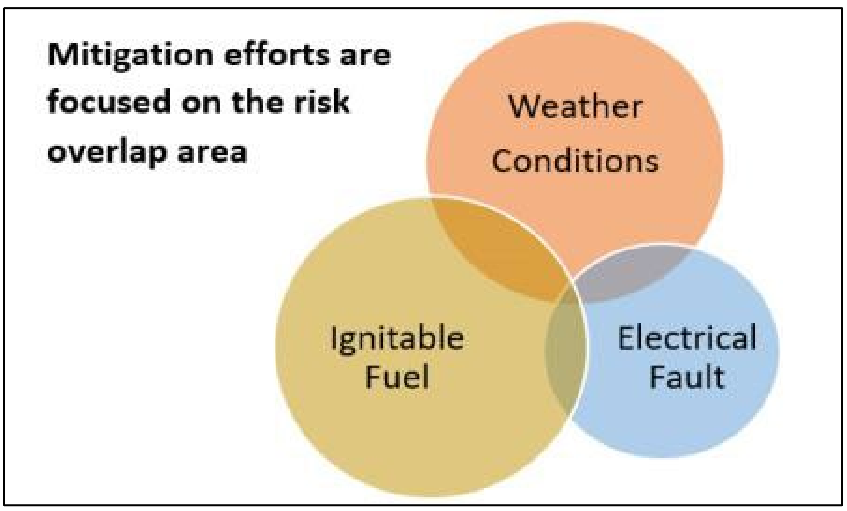

Figure 1: Utility Fire Risk Conceptual Model

Pacific Power's risk analysis first concentrates on weather conditions and ignitable fuels, to identify the geographic areas in Pacific Power's service territory at the greatest risk of catastrophic fire. The analysis also explores Washington's fire history, its recorded causes, the acreage impact of the fires, and the seasonality of fires. The analysis further considers historical outage data, reflecting the best available data regarding the potential for faults on the electrical system.

Pacific Power's analysis of the wildfire risk in Washington took advantage of a larger Pacific Power effort involving other states.[3] In 2018 and 2019, Pacific Power completed a wildfire risk analysis for its service territories that was patterned after the methodology developed after a long and iterative process in California. To take advantage of that experience, Pacific Power engaged fire-science engineering firm REAX Engineering Inc. to identify areas of elevated wildfire risk, which were designated with the name of Fire High Consequence Areas (FHCA).

Pacific Power and REAX first identified the general geographic areas subject to the risk analysis, which included all of Pacific Power's service territory and a 25-mile radius study area around all Pacific Power-owned transmission lines, as shown below:

Topography (elevation, slope, aspect) segmented into 2-km-square cells,

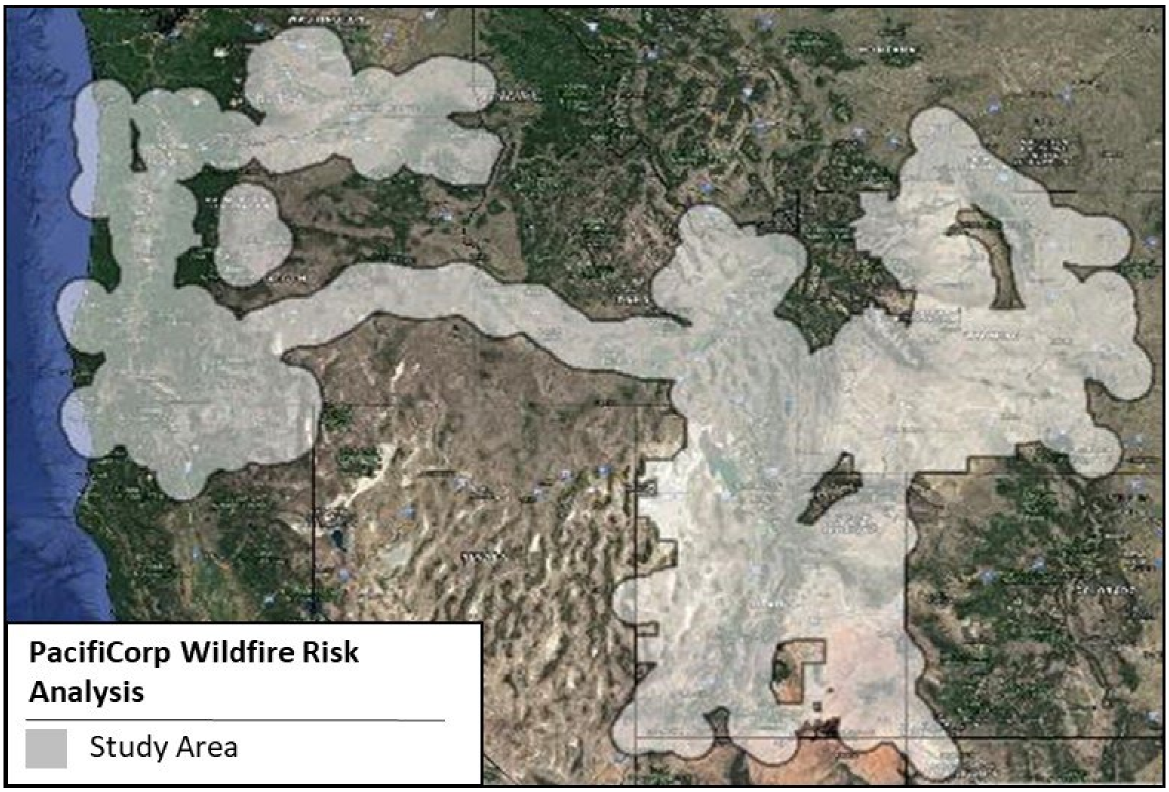

Figure 2: Study Area for Fire Risk Mapping Project

[3] Pacific Power is the division of Pacific Power that has service territory in Oregon, Washington, and California, Rocky Mountain Power is the division of Pacific Power that has service territory in Utah, Idaho, and Wyoming.

REAX then conducted a wildfire risk analysis on this area. REAX used the following data and processes:

1. Topography of the land, including elevation, slope and aspect
2. Fuel data (from a dataset known as LANDFIRE[4]) with 30 m pixel resolution, calibrated against one of 40 "fuel models[5]," which quantify fuel loading, fuel particle size and other quantities needed by fire models to calculate rate of spread.
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, determined by calculating the Fosberg Fire Weather Index, modified to recognize off-season moisture, as measured by Schroeder's ember ignition probability Pign.[7]
5. Estimated live fuel moisture.
6. Ignition modeling, using Monte Carlo-simulated ignition scenarios.
7. Fire spread modeling, Eulerian Level Set Model for Fire Spread (ELMFIRE), which is software for modeling wildland fire spread; ELMFIRE is used to run Monte Carlo-simulated burn scenarios that incorporate impacts to populations (by using the proxy of structures involved in any burn scenario, based on census tract data[8]), climatology, using spread algorithms developed in Eulerian Level Set Model for Fire Spread (ELMFIRE), conducted over a six-hour burn period, where fire type (surface, passive crown or active crown fire) in combination with flame length is critical to quantify output metrics including fire size (acres), fire volume (acre-ft) and the number of structures within the fire perimeter.

Through this process, individual blocks of geographic area, each 2-kilometer square, received a grid score corresponding to its relative wildfire risk. To establish the Fire High Consequence Area (FHCA), REAX used the prior California mapping project for calibration and assigned cell scores correlating with California statewide cell scores. This approach enabled an "apples-to-apples"

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[4] https://www.landfire.gov/datatool.php
[5] https://www.landfire.gov/fbfm40.php
[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).
[7] This metric MFFWI, was calculated in three-hour intervals for the time period of 1979–2017, and averaged over a six-hour period, since the early hours of a large fire are significant predictors for most catastrophic fires. The largest values were extracted, which involved about 200 days of hourly climatology inputs.
[8] http://www2.census.gov/geo/tiger/TIGER2010/TABBLOCK/2010/tl_2010_06_tabblock10.zip, ftp://ftp2.census.gov/geo/tiger/TIGER2010BLKPOPHU/tabblock2010_06_pophu.zip

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. REAX then used geographic information system (GIS) software algorithm "Jenks natural breaks" to segment areas into 33 families of risk areas[9], so that all cell areas were given a score from 0 to 32, as shown in Figure 3. Cell values do not imply direct mathematical relationships, but rather indicate bins of relative catastrophic wildfire risk when population density is factored into the weighting process.

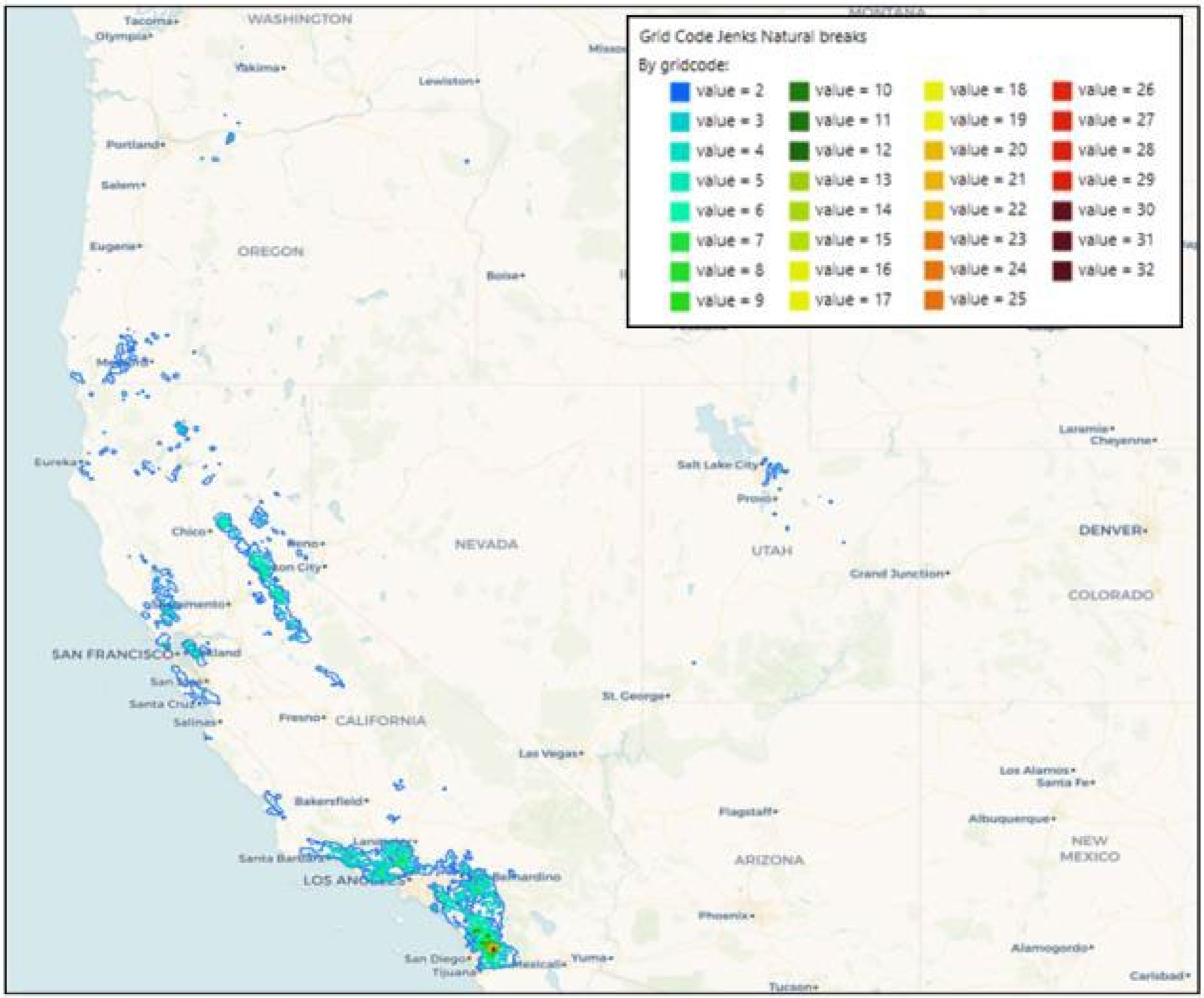


Figure 3 Grid Code of Jenks Natural Breaks

After REAX completed the computer modeling, a "ground-truthing" activity was completed by evaluating historic fire perimeters, existing Pacific Power facility equipment, and local conditions. The ground-truthing exercise generally validated the modelling performed by REAX and resulted in some relatively minor adjustments to the preliminary boundaries. Pacific Power is currently review and updating the FHCA and will provide an update in the 2024 WMP.

9 https://www.spatialanalysisonline.com/extractv6.pdf

The resulting Washington FHCA, together with magnified views on certain FHCA areas, is shown in the following figures.

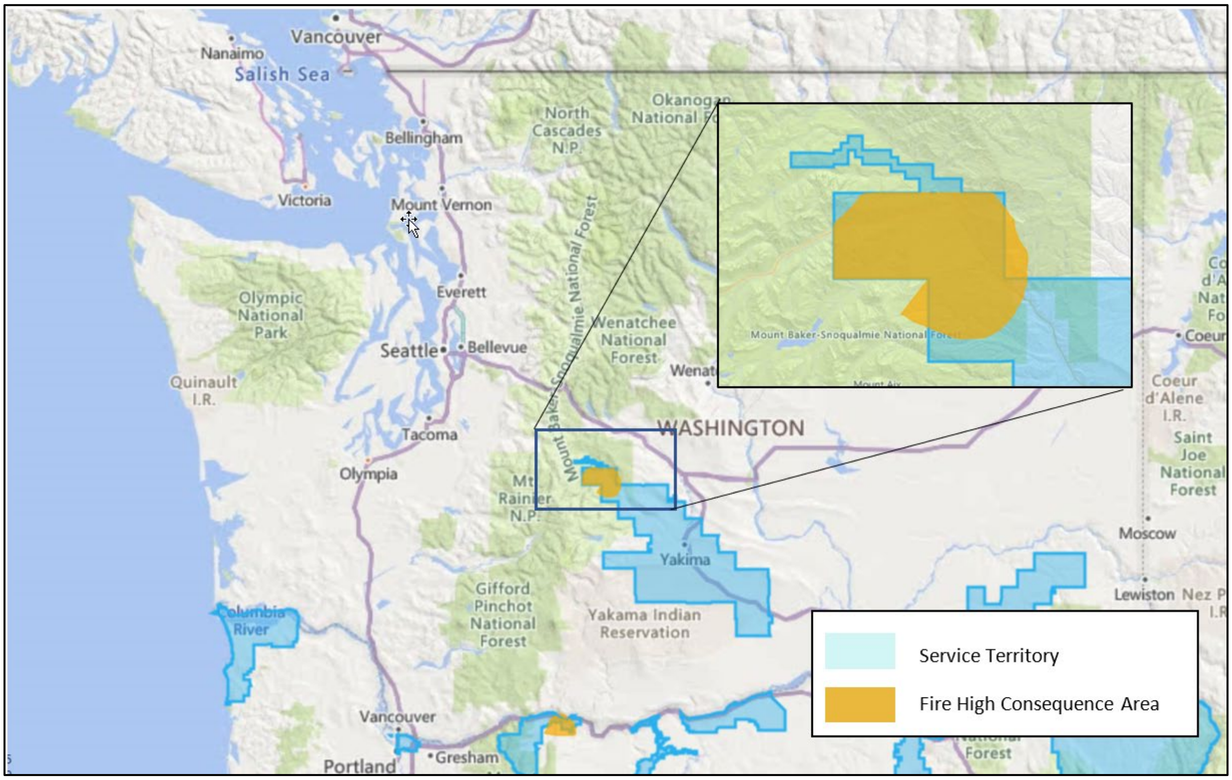


Figure 4: Washington Statewide FHCA Perimeters

1.3 Asset Inventory in the FHCA

In Washington, Pacific Power provides electricity to approximately 140,000 customers via 49 substations and 4,000 miles of overhead transmission and distribution lines, across a service territory encompassing nearly 2,800 square miles in Washington. The three primary categories of assets subject to wildfire mitigation treatment are described as follows:

Table 3: Primary Asset Categories

Asset Classification	Asset Description
Transmission Line Assets	Include conductor, transmission structures, and switches operating at a higher level voltage (typically, any line operating at or above 46 kV is a transmission line).
Distribution Line Assets	Include overhead conductor, underground cabling, transformers, voltage regulators, capacitors, switches, line protective devices, operating at a lower voltage (again, typically less than 46 kV).
Substation Assets	Include major equipment such as power transformers, voltage regulators, capacitors, reactors, protective devices, relays, open-air structures, switchgear and control houses.

Many wildfire mitigation strategies are focused on assets located in the FHCA. The following table includes the breakdown of Pacific Power's assets in the FHCA.

Table 4: Breakdown of Washington Assets in the FHCA

Asset	Total	FHCA	
	Line-Miles	Line-Miles	% of Total
OH Transmission	**664.4**	**0.0**	**0.0%**
69kV Transmission Lines	169.4	0.0	0.0%
115 kV Transmission Lines	212.7	0.0	0.0%
230 kV Transmission Lines	282.3	0.0	0.0%
OH Distribution	**3384**	**29**	**0.9%**
OH Lines - Miles	**4048**	**29**	**0.7%**
Substations	**49**	**0**	**0.0%**

1.4 State-Specific Fire History and Causes

To further develop an understanding of wildfire risks in both the state and company service territory, Pacific Power analyzed Washington fire history and ignition sources from 2007 through 2016, using data from the United States Forest Service. Ignition sources, both by number of ignitions in a given category, and by the amount of acres burned by ignitions in a particular category, are shown in the figures below. Whether assessed by the number of ignitions or by the acres burned from a particular cause, lightning was the leading cause of wildfire in Washington over the prior decade. The miscellaneous category is the next largest category. The miscellaneous category includes ignition causes attributed to others not classified and generally includes, fireworks, firearms and others.

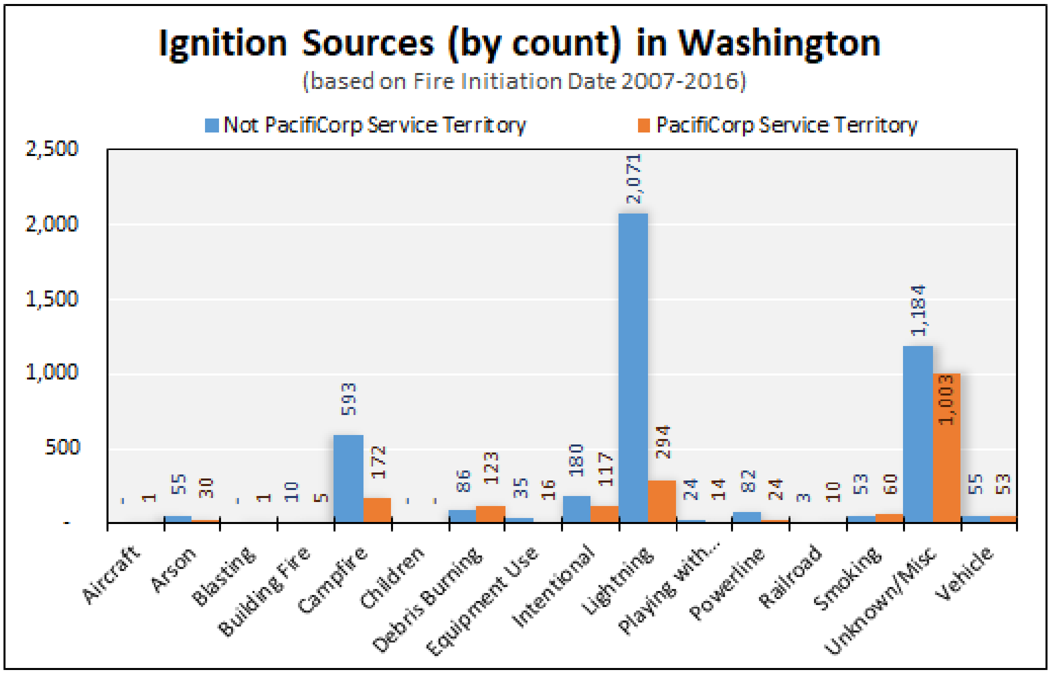


Figure 5: Fire History Ignition Source in Pacific Power's Washington Service Territory by Fire Threat Designation

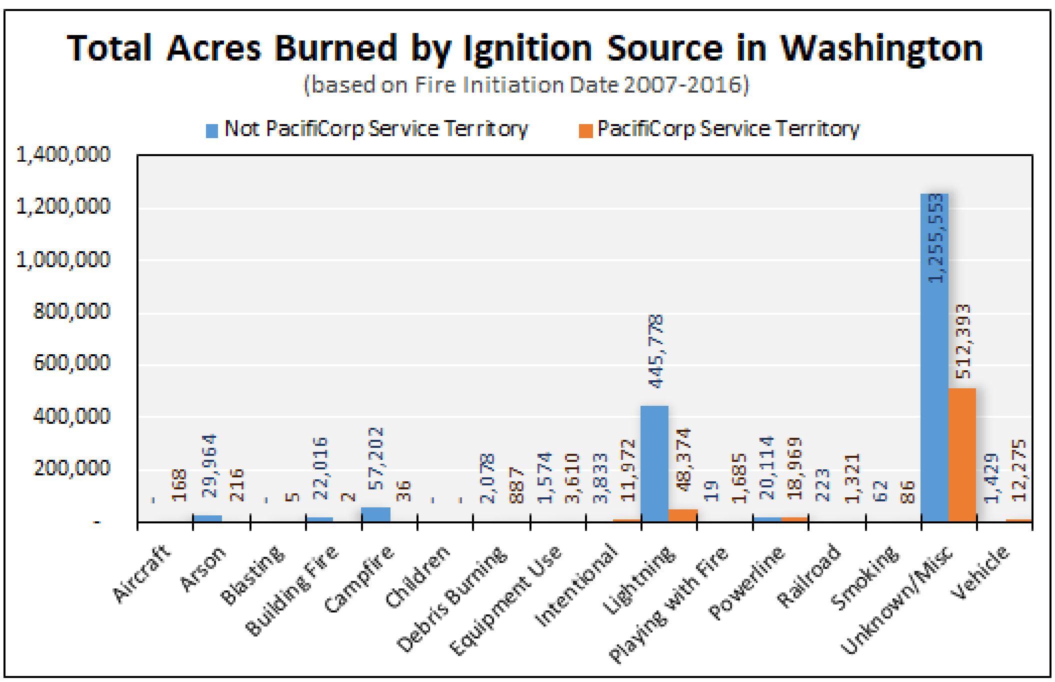
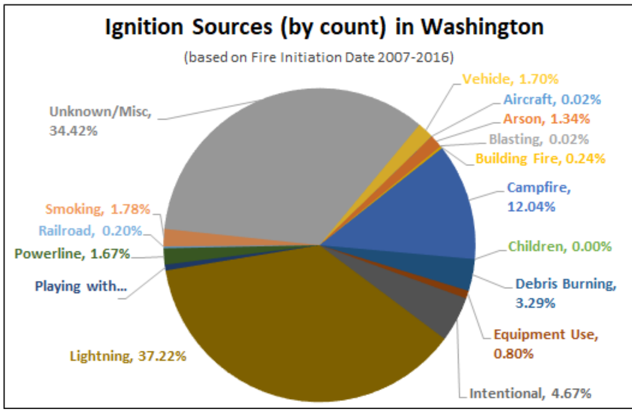


Figure 6: Fire History Total Acres Burned in Pacific Power's Washington Service Territory by Ignition Fire Threat Designation

The same data for the entire state of Washington, expressed as a percentage of the total in a pie chart format, is shown in the figures below.



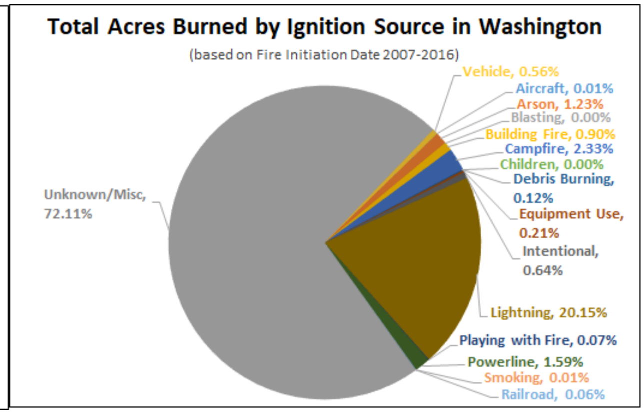


Figure 7: 2007 – 2016 Fire History Ignition Sources for the state of Washington; Percentages of Count and Total Acreage Burned

While the history outlined in the figures above shows that powerlines are not one of most significant causes of wildfire history in the state, it does indicate that powerlines reflect a category of appreciable risk to wildfires. In addition, consistent with similar studies in other states, it does appear that wildfires associated with powerlines may burn more acres as compared to other ignition categories. Wind is a major driver behind wildfire spread; wind is also an important cause of electrical faults on a system of overhead wires. Therefore, it is important that the company evaluates its asset performance and alters its strategies as it discovers strategies in which it can deliver safer and more reliable service.

1.4.1 Determining Historic Fire Season

Pacific Power plotted the cumulative acres burnt against the day of the year for the period from 2007 to 2020. While it does not mean that a wildfire cannot occur outside of fire season, the following figure supports the general conclusion that June 1 through October 1 is a good representation for when fire risk is elevated for the state as a whole, and more particularly in Pacific Power's Washington service territory.

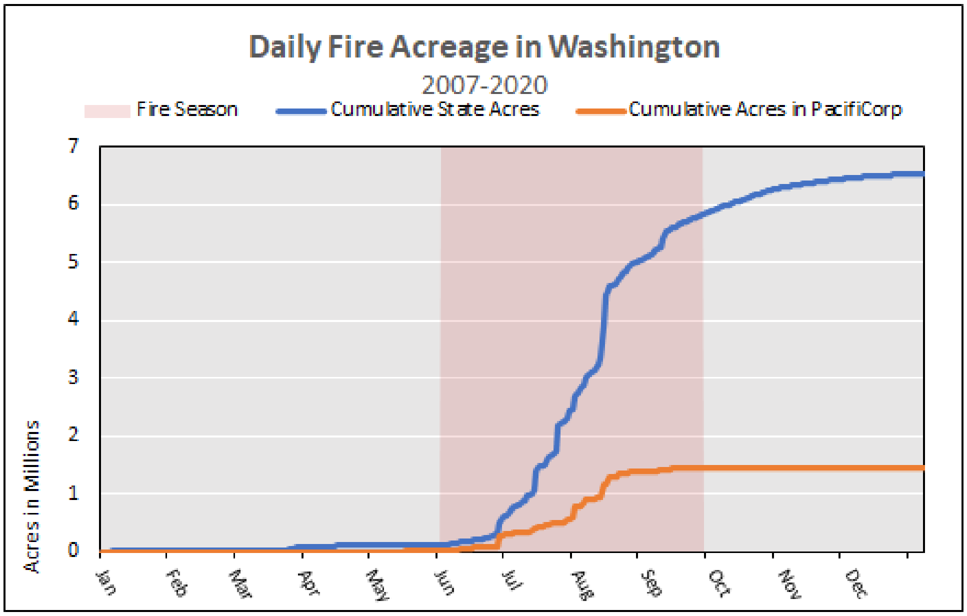


Figure 8: 2007–2020 Cumulative Acres Burned by Day of the Year in Washington

1.5 Assessment of Electric Utility-Related Fire Ignition Risk

Outage data is the best available data to utilities 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 occurs it could result in a spark, thus there is a risk of fire, therefore these events are classified as ignition risk drivers. 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 designed to determine which mitigation strategies are best suited to minimize fault events, thereby reducing the risk of fire.

1.5.1 General Outage Categories

Pacific Power maintains outage records in the normal course of business, as part of Pacific Power's historic efforts to assess and improve service reliability. These records document the frequency, duration, and cause of outages. Outage events experienced within Pacific Power's service territory were organized into categories included in Table 5; these are not necessarily the outage classification provided by field employees but are organized based on ignition risk drivers. As indicated in the table, three of the outage categories do not implicate the potential of a spark, and, therefore, were not classified as ignition risk drivers.

Table 5: Pacific Power's Outage Category Identification and Description

Outage Category[10]	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, contacts 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 probable causes identified
Operational	Outage event resulting from improper operating practice or other human error
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 outage categories, Pacific Power performed a multi-year look back in the outage records and focused on outages occurring during fire season (June 1 through October 1), contrasted against those occurring outside fire season. Figure 9 shows the annual cumulative ignition risk drivers in and out of fire season segmented by cause category. It further evaluates the two larger ignition risk drivers, specifically equipment failure (and analyzes this by components that failed or were damaged) in Figure 10 and contact from object to determine the initiators of the risk, such as vegetation, animals, or vehicle in Figure 11.

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

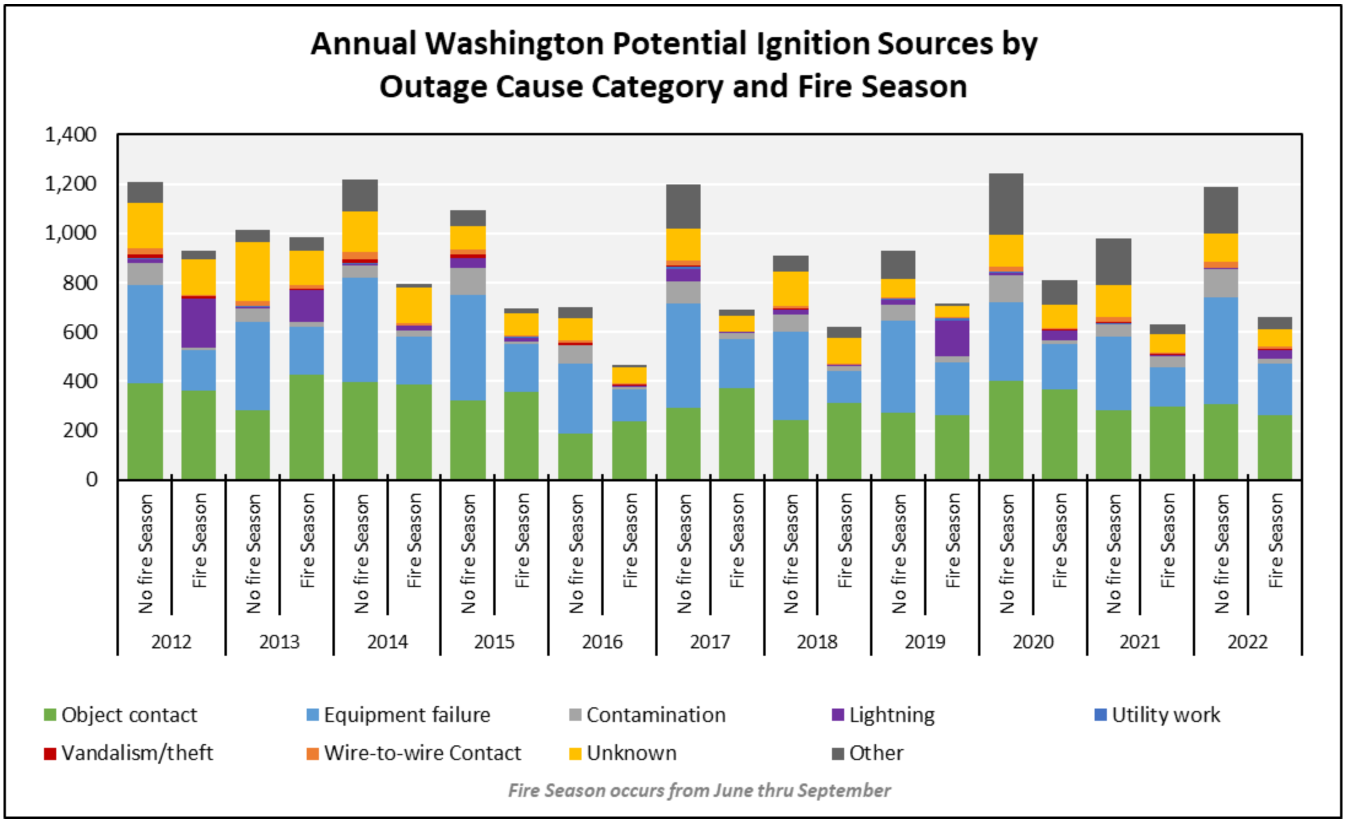


Figure 9: Cumulative Annual Distribution of Pacific Power's Washington Ignition Risk Drivers by Fire Season 2012-2022

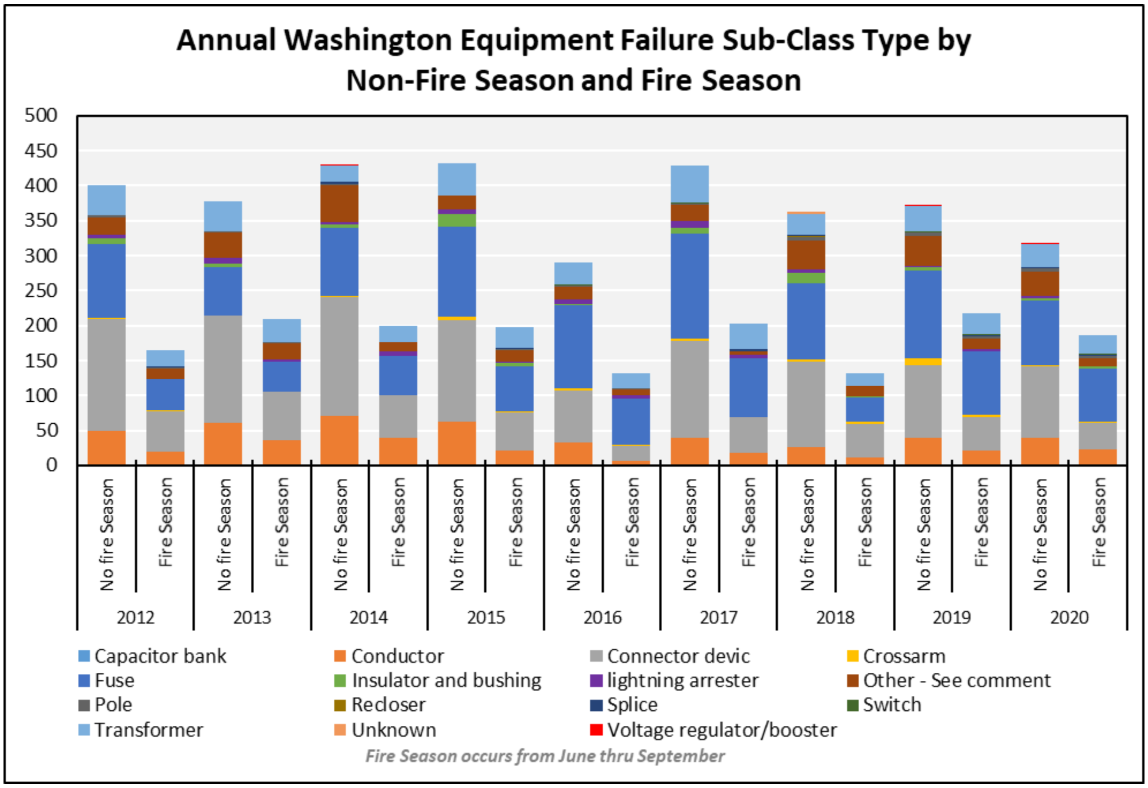


Figure 10: Detailed Breakdown of Equipment Failure Sub-Classes for Pacific Power's Washington Cumulative Annual Distribution by Fire Season 2012-2020

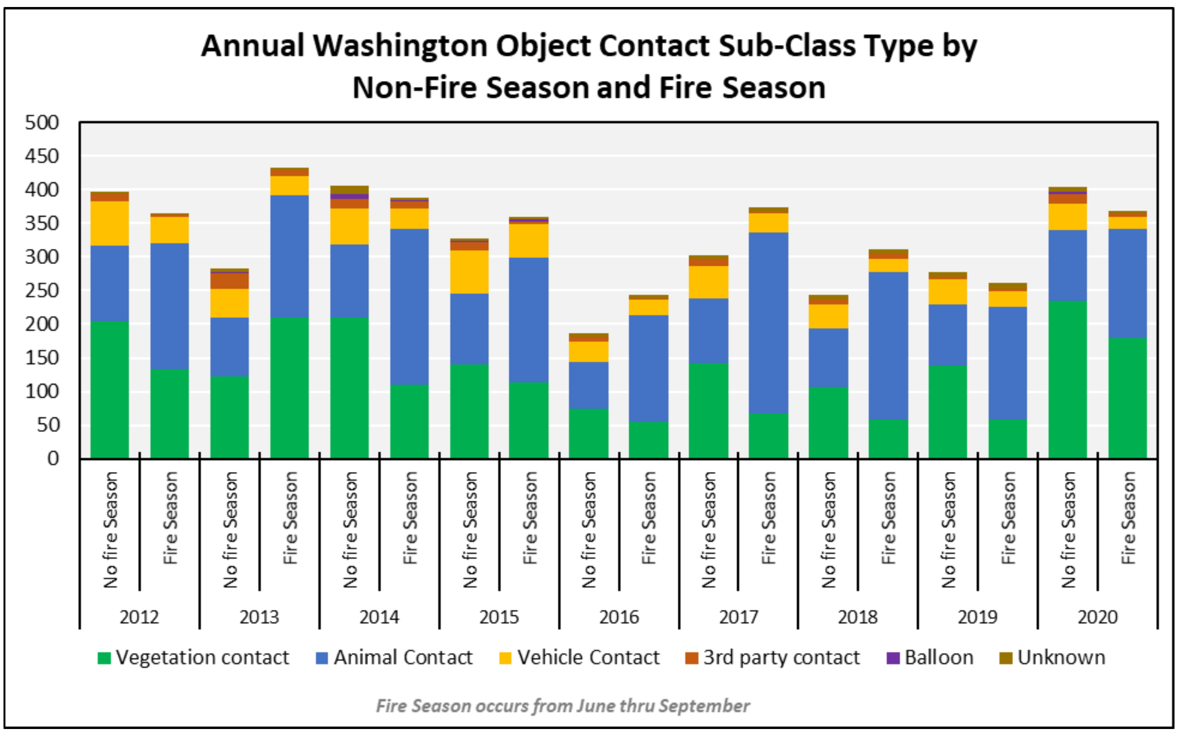


Figure 11: Detailed Breakdown of Object Contact Sub-Classes for Pacific Power's Washington Cumulative Annual Distribution by Fire Season 2012-2020

Pacific Power also analyzed the outages within the Fire High Consequence Areas (FHCA)[11], however due to the small footprint of FHCA in its Washington service territory it is unable to produce a meaningful comparison of inside/outside HFCA ignition risk drivers, shown in Table 6, below.

Table 6: Pacific Power's Washington Frequency of Potential Ignition Source by Outage Cause Category from 2012-2020, inside and outside FHCA

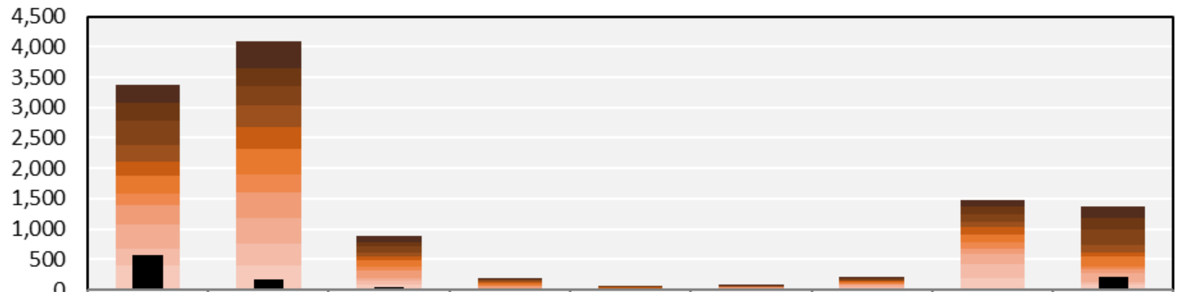
Potential Ignition Risk Driver by Outage Cause Category	2012-2020 Total Number of Events During Fire Season in Washington							
	Outside FHCA				Inside FHCA			
	Rank	Total Events	% Contribution	Events/ Year	Rank	Total Events	% Contribution	Events/ Year
Object contact	1	3,081	46%	342	1	21	54%	2.3
Equipment failure	2	1,632	24%	181	2	9	23%	1.0
Contamination	6	152	2%	17	5	1	3%	0.1
Lightning	4	580	9%	64	4	2	5%	0.2
Utility work	9	18	0%	2	6	0	0%	0.0
Vandalism/theft	8	22	0%	2	5	1	3%	0.1
Wire-to-wire Contact	7	41	1%	5	5	1	3%	0.1
Unknown	3	910	13%	101	3	3	8%	0.3
Other	5	327	5%	36	5	1	3%	0.1
Total	-	6,763	-	751	-	**39**	-	4.3

The following data is structured based on outage cause and evaluates year to year trends based on fire season. The company postulates that "wire down" events are the situation most likely to ignite ground fuels, and as such, tracking and diagnosing components which are involved in

[11] There are some constraints on tying outage records to the FHCA. The determination of an FHCA outage is based on the downstream topology within the operating device's Zone of Protection (ZOP). The ZOP of a device is all lines downstream from but not beyond any downstream auto isolating devices. It is to say that some portion of the ZOP touches the FHCA boundary, and may not be entirely encompassed within.

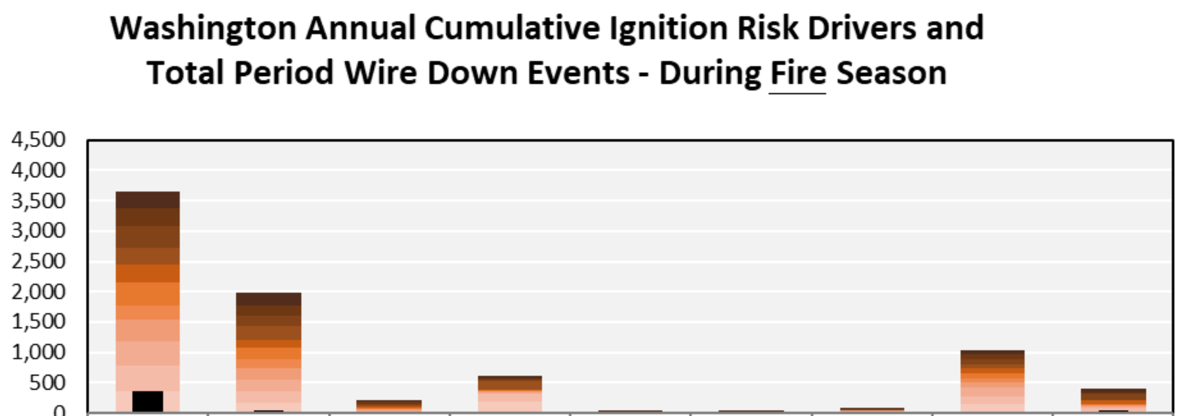
wire down events is important. For this reason, wire down events are overlaid in Figure 12 and 13 evaluating during fire season and non-fire season, below.

Washington Annual Cumulative Ignition Risk Drivers and Total Period Wire Down Events - During Non-Fire Season



	Object contact	Equipment failure	Contamination	Lightning	Utility work	Vandalism/ theft	Wire-to-wire Contact	Unknown	Other
2022	306	433	116	5	0	2	21	115	188
2021	285	297	49	0	3	7	21	127	192
2020	402	317	110	13	1	2	18	132	249
2019	275	369	69	17	4	3	5	74	115
2018	241	358	71	21	2	1	14	139	64
2017	293	422	89	51	8	8	21	126	181
2016	187	285	73	1	3	6	13	90	41
2015	322	426	114	37	3	11	19	95	67
2014	397	421	53	2	9	12	29	166	128
2013	281	362	52	7	2	3	19	236	50
2012	390	398	94	15	5	10	26	184	86
Total Wire Down Events	566	171	45	5	1	7	31	21	204

Figure 12: Cumulative Annual Ignition Risk Driver Events and Total Period Wire Down Events During Non-Fire Season



	Object contact	Equipment failure	Contamination	Lightning	Utility work	Vandalism/ theft	Wire-to-wire Contact	Unknown	Other
2022	262	211	18	36	1	3	12	66	51
2021	296	161	44	8	0	2	4	77	40
2020	366	187	14	40	0	2	9	94	100
2019	261	217	22	146	9	1	3	49	6
2018	311	131	22	2	0	3	4	103	47
2017	373	199	22	7	1	0	1	65	22
2016	238	130	12	1	2	3	7	66	8
2015	356	196	11	15	1	3	4	88	23
2014	385	196	23	20	1	0	13	143	15
2013	429	194	16	129	2	4	16	140	56
2012	362	163	11	199	2	8	6	144	32
Total Wire Down Events	370	51	10	19	0	4	12	14	43

Figure 13: Cumulative Annual Ignition Risk Driver Events and Total Period Wire Down Events During Fire Season

Finally, wire down analysis during both fire season and non-fire season was performed to identify those components possibly leading to the wire down event, which is shown in Figure 14. Note the detailed percent variations between non-fire season and fire season is shown parenthetically in the graphic's legend below. There appears to be no significant difference in equipment types based on fire seasons.

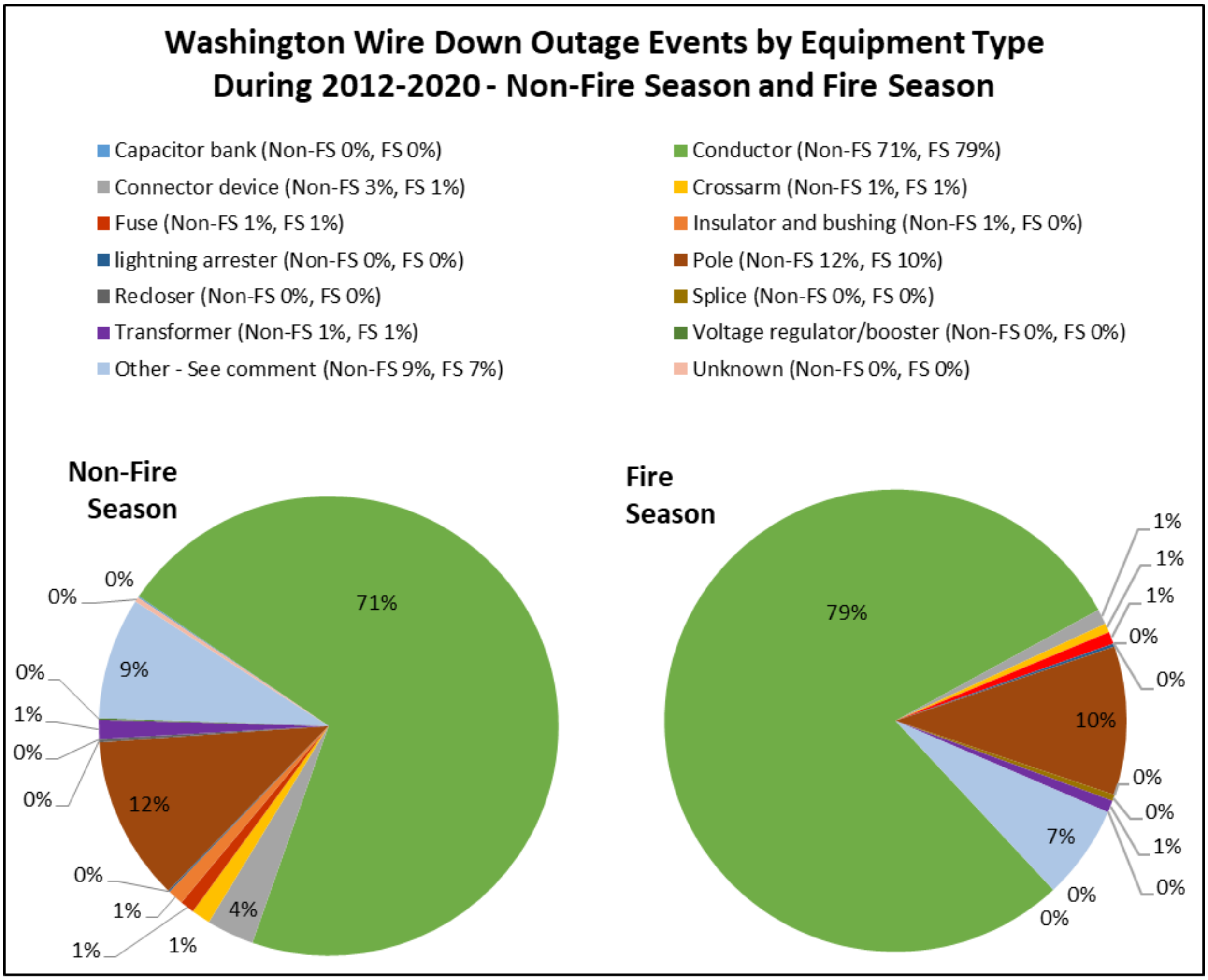


Figure 14: Wire Down Equipment Type Analysis During Non-Fire Season and Fire Season

1.6 Risk Assessment Conclusions

While a relatively small number of wildfires are attributable to powerlines, the potential magnitude of any wildfire event warrants significant wildfire mitigation efforts. The history of outages on the electrical network, and the faults underlying those outages, reflects the best available data for the wildfire risk assessment. Contact from Object presents the greatest utility related fire risk to Pacific Power's Washington service territory (at 42%), followed by Equipment Failure/Damage (at 21%), then Unknown, then Lightning. These top four categories account for 92% of all ignition risk drivers. As demonstrated by the data, areas inside and outside the FHCA do not seem to experience any statistically different frequency (based on the small dataset). Specific mitigation strategies designed to address these risks are discussed throughout the rest of this plan.

2. Situational Awareness

Situational awareness involves knowledge of the conditions that impact the potential for wildfire ignition and spread. Increasing its situational awareness of such conditions helps an electric utility implement operational strategies, respond to local conditions, and minimize the wildfire risk by making mitigation strategies more effective.

Weather Stations. Pacific Power obtains data regarding local conditions from many sources and uses the data to adjust its operations in both the short and long term. Local weather data remains a key input to this process and Pacific Power's overall situational awareness capability. To supplement existing local weather data and conditions, Pacific Power continues to evaluate the need for additional micro weather data in areas with a high risk of wildfires that could threaten the public and property. Currently, Pacific Power installed 6 as of end of year 2022 utility owned weather stations in Washington and plans to install an additional 12 weather stations in 2023 to obtain more granular local weather data in the FHCA and Public Safety Power Shutoff (PSPS) area. As the company's overall plan and situational awareness evolves, Pacific Power intends to evaluate this program for future expansion should additional or different data be needed.

Meteorology. The ability to gather, interpret, and translate data into an assessment of utility specific risk and inform decision making protocols is another key component of Pacific Power's situational awareness capability. To support this effort, Pacific Power has developed a meteorology department within the company's broader emergency management department. The objectives of this department are to supplement the company's longer term risk analysis capabilities with a real time risk assessment and forecasting tool, identify and close any forecasting data gaps, manage day to day threats and risks, and recommend changes to operational protocols during periods of elevated risk.

Advanced Forecasting. Pacific Power's meteorology team utilizes an impacts-based forecasting system which began in 2022. The Company has procured and implemented a suite of wildfire risk modeling tools that are used to forecast the risk of wildfire and the potential wildfire behavior should it occur. The tools can provide 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. Pacific Power's meteorology team analyzes weather model data and risk modeling output to produce a district-based, weather-related system impacts forecast which can be utilized to inform select programs.

3. 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 make sure that the asset is in conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and/or 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, nonconformance with Pacific Power construction standards, 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.
- **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.
- **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 to moderate risk to safety, reliability or worker safety
  - Priority D – issues that are not NESC conformance issues that are recorded for informational purposes
  - Priority G – grandfathered conditions that conformed to NESC requirements that were in place when construction took place but do not conform to more current code revisions

3.1 Current 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, and detailed inspections are performed less frequently, with a more detailed scope of work. 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. The inspector conducting the inspection will assign a condition code to any conditions found and the associated priority level in Pacific Power's facility point inspection (FPI) system. 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 is different in different state jurisdictions. In all cases, the timeline for corrections takes into account the priority level of any identified condition. An A priority level condition is addressed on a much shorter timeframe than a priority B condition.

3.2 Proposed Inspection and Correction Programs

The existing inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate some wildfire risk by identifying and correcting Conditions which, if uncorrected, could ignite a fire. Recognizing the growing risk of wildfire, Pacific Power is supplementing its existing programs to further mitigate the growing wildfire specific operational risks and create greater resiliency against wildfires. There are three primary elements to this proposal: (1) creating a fire threat classification for specific Condition Codes; (2) increasing inspection frequencies in Fire High Consequence Areas; and (3) reducing Correction timeframes for fire threat Conditions.

Fire Threat Conditions. Pacific Power designates certain conditions as "fire threat conditions." Each condition is still assigned a condition code (e.g., CONDFRAY for a damaged or frayed primary conductor) – but certain condition codes are categorically designated as a fire threat condition. Accordingly, if a condition is designated under a particular condition code associated as a fire threat, the condition will also be designated as a fire threat condition. To this end, a review was performed on all existing condition codes to determine whether the condition code could have any correlation with fire ignition. Condition codes reflecting an appreciable risk of fire ignition were designated as fire threat conditions. For example, if a damaged or frayed primary conductor was observed during an inspection, the inspector would record condition code CONDFRAY, which is designated as a fire threat condition because the condition could eventually result in an ignition under certain circumstances. In contrast, the observation of a missing or broken guy marker would result in the condition code GUYMARK, which is not designated as a fire threat condition.

Inspection Frequency. Pacific Power's plans include an increase to the frequency of certain inspection types for assets located in the FHCA as well as detailed inspections of overhead distribution throughout all of Washington. 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 fire risk conditions. Inspection frequencies for Washington asset types are summarized in the following table:

Table 7: Current and Proposed Inspection Frequency in the FHCA

Inspection Type	Legacy Frequency (in years)	Proposed Inspection Frequency- non FHCA (in years)	Proposed Inspection Frequency- FHCA (in years)
OH Distribution (Less than 46 kV)			
Visual	2	2	1
Detailed	20	10	5
Pole Test & Treat	20	20	20
OH Local Transmission (more than 46 kV and Less than 200 kV)			
Visual	2	2	1
Detailed	10	10	5
Pole Test & Treat	10	10	10
OH Main Grid (More than 200 kV)			
Visual	1	1	1
Detailed	2	2	2
Pole Test & Treat	10	10	10

Correction Timeframe. Pacific Power has further mitigated wildfire risk by reducing the time allowed for correction of fire risk conditions in the FHCA. As expressed above, certain types of conditions have been identified as having characteristics associated with a higher risk of wildfire potential. Accordingly, Pacific Power is prioritizing those conditions for correction. Because of the risk of catastrophic wildfire in the FHCA, Pacific Power has implemented an expedited correction schedule for fire threat conditions in the FHCA, requiring that Priority A conditions be corrected on a 30-days and that B fire risk conditions be corrected within 12 months. Correction timeframes for fire threat conditions in the FHCA are summarized in the following table:

Table 8: Current and Proposed Correction Timeframes for Fire Threat Conditions in the FHCA

Condition	Correction Timeframes
A – imminent	Immediate
A – fire risk and in the FHCA	30 days
B – fire risk and in the FHCA	12 months

3.3 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 the 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.

4. Vegetation Management

Vegetation management is generally recognized as a significant strategy in any Wildfire Mitigation Plan. Vegetation coming into contact with a power line could be a 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. This objective is in alignment with core Wildfire Mitigation Plan efforts, and continuing dedication to administering existing programs is a solid foundation for Pacific Power's Wildfire Mitigation Plan efforts. To supplement the existing program, Pacific Power vegetation management implements additional Wildfire Mitigation Plan strategies in Fire High Consequence Areas (FHCA).

4.1 Regular Vegetation Management Program

Pacific Power's vegetation management program is described in detail in Pacific Power's Transmission & Distribution Vegetation Management Program Standard Operating Procedures ("Standard Operating Procedures"). The focus of Pacific Power's vegetation management efforts is different for distribution lines and transmission lines. In both cases, typical work functions include pruning and tree removals. Pacific Power prunes trees to maintain a safe distance between tree limbs and power lines. Pacific Power also removes trees that pose an elevated risk of falling into a power line. Pacific Power uses more restrictive clearance protocols under transmission lines and typically has wider rights-of-way that allow it to remove vegetation and promote low-growing plant communities. 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.

Distribution – Cycle Maintenance. Vegetation management on distribution circuits is completed on a cycle basis every three years. Circuits are inspected and where work is identified, vegetation is pruned or removed to comply with defined minimum post-work clearance specifications. Because some trees grow faster than others, minimum post-work clearance specifications vary depending on the type of tree being pruned. For example, faster growing trees need a greater minimum post-work clearance to maintain clearance throughout the cycle. The minimum post-work clearance specifications consider tree growth rates and duration of the work cycle.

Pacific Power also integrates spatial concepts to distinguish between side clearances, under clearances, and overhang clearances. Recognizing that some 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. Increasing overhang clearances also reduces the potential for any contacts due to falling overhang.

The minimum post-work clearance specifications are designed to maintain worker safety, minimize or prevent vegetation contact with conductors or conditions that pose a threat to electrical infrastructure, and minimize vegetation caused outages throughout the cycle. The specific distances for the minimum post-work clearance specifications are set forth in Section 5.2 of the Standard Operating Procedures as follows:

Table 9: Distribution Minimum Vegetation Clearance Specifications for a Three-Year Cycle

Three-Year Cycle			
	Slow Growing (< 1 ft. /yr.)	**Moderate Growing (1-3 ft./yr.)**	**Fast Growing (>3 ft./yr.)**
Side Clearance	8 ft.	10 ft.	12 ft.
Under Clearance	10 ft.	12 ft.	14 ft.
Overhang Clearance	12 ft.	12 ft.	12 ft.

When a tree is pruned, natural target pruning techniques are used to protect the health of a tree. 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.[12] Consequently, an actual cut is typically beyond the minimum clearance distance listed in the table above.

Pacific Power also removes high-risk trees as part of distribution cycle work, to minimize vegetation contact. High-risk trees are defined in the Standard Operating Procedures 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."[13] 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 hazard trees, Pacific Power uses the practices set forth in ANSI A300 (Part 9); and Smiley, Matheny and Lilly (2011), Best Management Practices: Tree Risk Assessment, International Society of Arboriculture. In summary, Pacific Power identifies high-risk trees for removal through a Level 1 visual assessment, as defined in ANSI A300 (Part 9), with particular attention to the prevailing winds and trees on any uphill slope. Suspect trees that require further inspection may be subjected to a Level 2 assessment, as outlined in ANSI A300 (Part 9), to further 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. Discretionary removals are also pursued (e.g., trees where removal may take similar time as it would to prune) to reduce future work volumes. 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.

[12]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.)
[13]See Table 2 of FAC-003-04, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

Transmission Line Vegetation Management. Vegetation management on transmission lines is also focused on maintaining clearances, but 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[14]). Accordingly, rather than scheduling vegetation management work for transmission 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 clearance as specified in this table:

Table 10: Transmission Minimum Vegetation Clearance by Transmission Line Voltage

Transmission Clearance Requirements (in feet)								
	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

Taking advantage of greater legal rights to manage the vegetation in the right-of-way for transmission lines, Pacific Power employs "Integrated Vegetation Management" (IVM) practices, where possible, 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 managing the species of trees and other vegetation growing in the right-of-way. Under such an approach, Pacific Power removes tree species that could potentially threaten clearance requirements, while encouraging low growing cover vegetation, which would never implicate clearance issues.

Line Patrolmen inspect most transmission lines annually and notify the vegetation management department of any vegetation conditions. Regional foresters in the vegetation management department and/or vegetation management contractors 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, which is consistent with industry standards and best management practices. Vegetation work on local transmission overbuild is completed on the distribution cycle schedule and inspected accordingly.

All of these strategies and techniques are described further in the Standard Operating Procedures. The current form of the Standard Operating Procedures was first published in 2008, and periodic updates to content have been made. The most current version is Revision 07, dated May 13, 2019, which incorporates provisions for the new mitigation strategies described below.

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

4.2 New Wildfire Mitigation Plan Strategies

After identifying lines in the FHCA, Pacific Power is implementing three new elements to its long-term vegetation management program for the purpose of further mitigating wildfire risk in those areas. First, Pacific Power vegetation management will conduct annual vegetation patrols on lines in the FHCA. Second, increasing the minimum clearance distances applicable to distribution cycle work completed in the FHCA. Third, completing annual pole clearing on subject equipment poles located in the FHCA.

Annual Vegetation Patrols. Pacific Power vegetation management is transitioning to annual vegetation patrols for lines located in the FHCA. Although conducting annual vegetation patrols is above and beyond traditional industry standards, Pacific Power vegetation management believes that this tool is an effective strategy to identify high-risk trees at an early stage. This strategy facilitates removal of high-risk trees, minimizing fall in risk and wildfire ignition risk.

Extended Clearances. Pacific Power has also adopted increased minimum clearance specifications for distribution cycle work in the FHCA. The minimum clearance specifications require pruning to at least 12 feet, in all directions pending any site-specific adjustments and considerations. As discussed above, minimum clearance specifications dictate 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 minimum clearance specifications for the FHCA are as follows:

Table 11: Distribution Minimum Vegetation Clearance Specifications in the FHCA

	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.

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 of clear space around a subject pole and applying herbicides to prevent any vegetation regrowth (unless prohibited by law or the property owner). 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, where data exists, 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.

Alternative Strategies for Potential Future Deployment. Moving forward, Pacific Power vegetation management is planning to implement the three mitigation projects described above through time considering contractor resources to implement the work. Pacific Power will consider and 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 Wildfire Mitigation Plan. In particular, Pacific

Inventory Reduction Projects. Pacific Power may consider implementing enhanced inventory reduction projects in Washington. The goal of inventory reduction is to remove trees before such trees ever require vegetation work. Unless property rights in the right-of-way were substantially enlarged and other constraints addressed, it would not be feasible to remove all trees that have the potential to implicate clearance issues or become high-risk trees (i.e., by definition, all trees eventually become high-risk trees when they die). Instead, an inventory reduction program targets specific areas of particular concern, with the goal of materially reducing the total number of trees that could eventually pose a risk of vegetation contact. Determining which areas and trees to target implicates a certain degree of subjective judgment and evaluation of local conditions. Factors for consideration include tree species, tree height, weather patterns, topography, line design and tree disease patterns.

5. 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 means 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 proposes 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. This particular section on system hardening, however, 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.

5.1 FHCA Line Rebuild Program

Pacific Power has evaluated specific areas for system hardening work. The wildfire risk assessment, discussed in Section 1, is an important factor in evaluating where work is appropriate. Pacific Power has identified areas in Washington where bare overhead wire may be replaced with covered conductor. Where appropriate, poles will either be replaced 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. In all, the end effect will be more tolerant to incidental contact, while also being certain to tolerate fault event arc energy levels.

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. 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 is in the FHCA.

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

The dominant characteristic of covered conductor is that the metal conductor which actually carries electricity is sheathed in a plastic covering. As a comparison for the lay person, covered conductor is like an extension power cord that you might use in your garage. The plastic coating provides insulation for the energized metal conductor inside the plastic coating. 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 plastic sheathing provides an insulating effect. It is this insulating effect which reduces the risk of wildfire, by greatly reducing the number of faults that would have occurred had bare conductor been used.

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, however, have markedly 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 thermal insulation (i.e. because bare wires are exposed to air, bare wires can cool easier). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially when carrying snow or ice, meaning that more and/or stronger poles may be required when using 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 or a Mylar balloon carried by the wind drifting into a line, contact from those objects with energized bare conductor causes 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 reasonably linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind, in particular, is the driving force behind catastrophic 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 catastrophic 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.

In sum, at a very basic level, covered conductor is safer overall compared to bare conductor. Not only does covered conductor reduce the risk of wildfire, it is less dangerous to contact a covered conductor compared to a similar voltage bare conductor. Combined with the substantial wildfire mitigation benefits, covered conductor is the preferred design for rebuild projects. There are, however, unique challenges implicated in making it harder to spot a low-hanging or downed line.

Pacific Power also evaluated the costs and benefits of underground design 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. Unfortunately, because of cost and operational constraints, the functional realities of underground construction prevent widespread application as a wildfire mitigation strategy.

Nonetheless, Pacific Power is using an underground design as part of the rebuild projects when functional and cost-effective. Through the design process, each individual rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. As a practical matter, the great majority of the rebuilds will be covered conductor, which is true of planned investment in Washington. This outcome is consistent with emerging best practices. Utilities in geographic areas with extreme wildfire risk, including in California and Australia, are trending heavily towards use of covered conductor, with limited applications of underground construction where appropriate. Indeed, sourcing material for the planned projects is challenging because of the industry trend towards use of covered conductor as a primary wildfire mitigation strategy. On a related note, the company remains willing to consider additional underground applications. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with governing electric service regulations, Pacific Power will work with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction, if covered conductor is the least cost option for a rebuild project.

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.

Non-Expulsion Fuses. 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 plans to replace expulsion fuses with non-expulsion fuses as a part of the FHCA line rebuild program in conjunction with the installation of covered conductor.

5.2 Reclosers & Relays for Advanced System Protection Program

Pacific Power plans to replace electro-mechanical relays with microprocessor relays. Microprocessor relays provide multiple wildfire mitigation benefits. Microprocessor relays are able to exercise programmed functions much faster than an electro-mechanical relay. 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. 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. 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.

6. Operational Practices

6.1 System Operations

The manner in which an electrical system is operated can also help mitigate wildfire risk. Pacific Power has specific procedures addressing system operations during fire season. These procedures are designed to reduce the potential for ignition of a fire from sparks emitted when a line is re-energized with a disturbance still on the line. Recognizing the increasing magnitude of the wildfire risk, Pacific Power significantly augmented operating procedures in June 2018 to incorporate a more conservative approach designed to reduce the potential of fault-based ignitions on Pacific Power's electrical network. From a practical perspective, the procedures implicate two primary subject areas: (a) settings for automatic reclosers and (b) line testing after lock-out.

Automatic reclosers are currently deployed on various transmission lines and distribution circuits throughout Pacific Power's service territory. When a line trips open, an automatic recloser may operate to close the circuit very quickly, so long as the cause of a momentary trip has cleared. The reclosing function allows Pacific Power to maintain service on a line that had tripped, rather than opening the circuit and de-energizing the line. In general, automatic recloser operation is beneficial because it reduces outages and improves customer reliability. The actual operation of recloser equipment does not directly present wildfire risk, as the recloser equipment itself does not emit sparks or otherwise pose an ignition risk.

The operation of automatic reclosers, however, indirectly implicates some degree of ignition risk. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings in an attempt to re-energize the line. If the cause of the fault is no longer present when the device recloses, the line will re-energize resulting in limited impact to customers. If the cause of the original fault still remains when the device recloses, however, the original fault may persist and, depending on the circumstances, potentially result in arcing or an emission of sparks. As a result, in some limited circumstances, the second fault scenario could lead to a fire ignition. Accordingly, automatic recloser settings can have a significant impact on wildfire mitigation.

The risk associated with line-testing on overhead lines is very similar. If a breaker has "locked-out" – meaning that it has opened and no longer conducts electricity – a system operator will sometimes "test" the line. To test the line, the system operator 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. At the same time, line-testing can result in the emission of sparks if a fault has not yet cleared when the line is tested. Accordingly, a "no-test" policy reduces the risk of ignition, and a "no-test" policy is applicable in certain circumstances during fire season.

In general, these system operating procedures are more restrictive when wildfire conditions are elevated. The specific circumstances in which automatic reclosers are disabled and no-test applies, on both transmission and distribution lines, are fully detailed in the procedures.

7. Field Operations

During fire season, Pacific Power modifies the way it operates in the field to further mitigate wildfire risk. In particular, field operations 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.

Work Restrictions. Pacific Power field operations 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 below.

During fire season generally, field 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 wildland vegetation, certain restrictions may apply, including:

- **Hot Work Restrictions.** Field 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.** Field 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.

Vehicles. Vehicles can be a source of ignition. As discussed above, field 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, field operations plan to convert, over time, the vehicle exhaust configuration of work trucks. To accomplish this objective, field operations will strategically convert some vehicles in districts with the greatest amount of FHCA. Long term, when new vehicles are purchased, Pacific Power plans to purchase trucks with a vehicle exhaust configuration which minimizes ignition risk.

Additional Labor Resources. Some wildfire mitigation activities require the time of field personnel, including in two key areas: (a) supporting system operations in administering the procedures discussed above and (b) responding to outages during fire season.

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 above, there are system operations procedures during wildfire season for disabling automatic recloser functions 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. After a fault results in an outage, all or part of a circuit might remain de-energized while restoration work is performed, depending on the design, loading conditions, and sectionalizing capability of the circuit experiencing the outage. Occasionally, additional foreign objects, such as tree limbs or other debris, can come into contact with the de-energized line and remain undetected throughout the duration of restoration efforts. Under normal operating procedures and consistent with prudent utility practices, a line is typically re-energized as soon as restoration work is complete. Consequently, a re-energized line could immediately experience a new fault if some contact between the line and foreign object had occurred while restoration work was being performed. The new fault would, of course, present additional wildfire risk, because of the potential of a spark being emitted as a result of a fault occurring when the line was re-energized. 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.

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).

Mobile Generators. Pacific Power has a mobile generator to assist with emergency response efforts. In short, when power on the electrical network is lost, either proactively or as the result of wildfire damage, a mobile generator unit can be dispatched to provide power. The generator is transported via tractor trailer to a specific location based on real-time circumstances. For example, a mobile generator may be dispatched by the Emergency Operations Center to mitigate the impact of a proactive de-energization, as discussed in greater detail in the Public Safety Power Shutoff section below. There are constraints in connecting the generator, and each deployment is examined on a case-by-case basis.

Water Truck Resources. Pacific Power has water trucks 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 truck to join field personnel working in the field. As discussed above, the water truck 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 truck could be used to assist in the suppression of a small fire. Field operations currently has eight water trucks for use in such applications. In addition, the company plans to purchase two water trucks and one trailer.

8. Public Safety Power Shutoff (PSPS)

Pacific Power is sensitive to the ramifications of a Public Safety Power Shutoff (PSPS). Turning off the power is contrary to an electric utility's core mission and culture. And Pacific Power understands that turning off power can have negative consequences for customers and the public at large.

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.

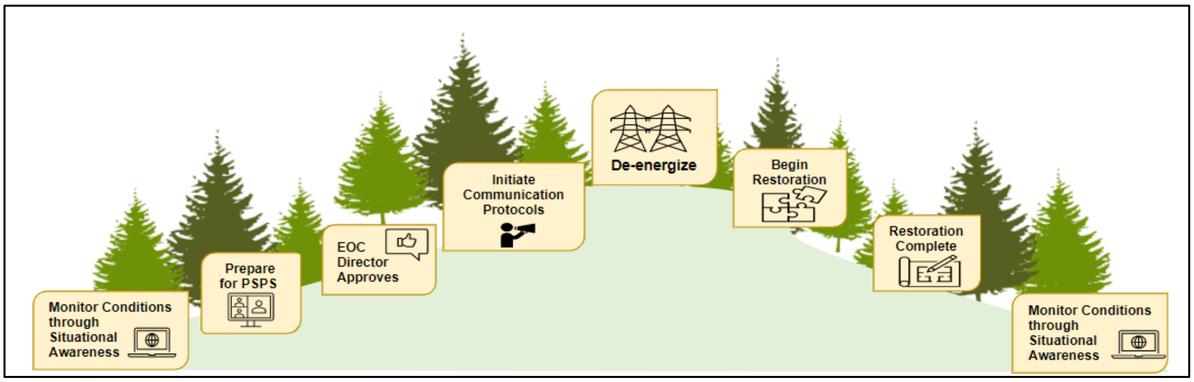


Figure 15: De-Energization Overview

Since initial development in 2019, Pacific Power has yet to implement an actual PSPS event in Washington. Pacific Power continues to meet with representatives of local government and the emergency response sector to review and refine PSPS protocols. For 2022 and beyond, the company is further evaluating the strengths and weaknesses in the PSPS plan and will make updates and revisions accordingly.

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, if needed as a measure of last resort, 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

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. They 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, as shown below.

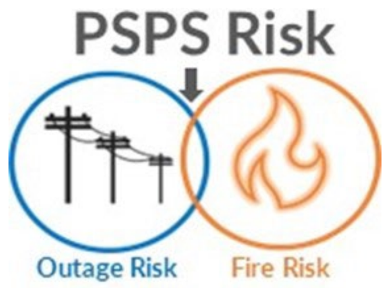


Figure 16: PSPS Assessment Methodology

Assessing the Potential for a PSPS

Meteorology generates a daily weather briefing that includes a system impact forecast matrix for Pacific Power's entire service territory. This matrix includes a district-level forecast of weather-related outage potential and fire risk as described in detail in Section 1 of this document. When the district fire risk is significant or extreme, meteorology will use a combination of models and subject matter expertise to identify circuits of concern. Emergency management will also schedule a coordination meeting to discuss circuits of concern and to determine the appropriate operational response, up to and including PSPS. A 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.

8.2 De-Energization Watch Protocol

Pacific Power actively monitors real-time weather conditions. When real-time observations and weather forecasts indicate extreme risk, a de-energization watch protocol is initiated that includes:

- Activation of an "Emergency Coordination Center" (ECC).
- Communication with local public safety partners.
- 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 coordination. The ECC is led by an Incident Command 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 company's customer service team then coordinates through the ECC to confirm customer lists for the subject area to develop a communication plan for customers that may be 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 remotely monitor from the operations center.

PSPS is a temporary mitigation measure. Consistent with existing regulations and the general mandate to operate the electrical system safely, the ECC has discretion to determine when (or if) a PSPS is appropriate. Given the potential impacts to customers and communities, Incident Command will consider all available information, including real-time feedback and other considerations from other ECC participants, public safety partners, and field observers, to determine whether PSPS should be executed. As a matter of practical reality, Incident Command 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. Additionally, Incident Command may decide to further refine the PSPS areas identified.

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 Incident Command, an internal notification is sent to initiate appropriate communications 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 of community resource centers (CRC), if needed, and additional field resources may be deployed or staged accordingly. Conditions are continually monitored; when they no longer meet the requirement for a PSPS, 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 the company will always strive to provide as much notice as practical to impacted parties. Nonetheless, PSPS decisions are made based on weather forecasts, and weather can change quickly or dramatically with little forewarning. This requires some degree of balancing in communication protocols and, 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 affected areas to advise on protocols that 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 communication to entities like non-emergency dispatch centers, emergency management, fire agencies, and law enforcement agencies allow them to prepare for anticipated operational impacts internally and mitigate any community-wide impacts that may occur because of de-energization. Collaboration with these agencies also supports impact reduction of de-energization and communication of 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 that include PSPS boundaries for areas subject to de-energization. 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 other entities as applicable. The company will also 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. Upon activation of an ECC, they 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. Additionally, Pacific Power will provide, where possible, GIS shapefiles to communications facility operators in potentially impacted areas.

During a PSPS event, Pacific Power recognizes the importance of providing additional geographic details of the affected area and plans to provide them to public safety partners through a secure web-based public safety partner portal, beginning in 2024. The public safety partner portal is expected 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.

Customers

The Pacific Power PSPS webpage[15] provides timely and detailed information regarding potential and actual PSPS events for a specific location. The website has the bandwidth to manage site traffic under extreme demand because it has implemented bandwidth capacity to a level that will allow for increased customer access while maintaining site integrity. The PSPS webpage provides visitors with an interactive map where users can input an address to see if a residence

[15] See Public Safety Power Shutoff (pacificpower.net).

or business could be affected by a PSPS. When a potential PSPS is announced, the map is updated to show the 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 a Pacific Power ‘app’ is available for mobile devices, which enables customer access to real-time outage updates and information.

Customers with specific language needs can also 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 are looking for.

Pacific Power’s communications plan also includes procedures that ensure appropriate notifications (additional if time allows) to medically vulnerable customers. The utility leverages insight from its partners and customer records to pre-identify these customers. Upon activation of the ECC, customer care agents will attempt, time and circumstances allowing, to make personal outbound calls with known vulnerable customers.

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 to 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 X (formerly 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 with:

- The impending PSPS execution, with information about the estimated date, time, and duration of the event.
- A 24-hour means of contact for customer inquiries, and 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 given that the company's fundamental business objective is to keep the grid energized except under the most extreme conditions.

Table 12 illustrates Pacific Power's planned PSPS notification timeline for customers, public safety partners, and operators of critical facilities. Timelines may be reduced if rapidly changing conditions do not allow for advance notification. In these cases, the company will make all notifications as promptly as possible.

Table 12: 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, businesses, and communities, and plans to provide support to impacted communities through community resource centers as appropriate. By taking advantage of established relationships with community and public safety partners, a CRC may be activated in an impacted area to give community members and businesses access to items that may be affected by 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/or a satellite phone
- Television and radio
- On-site medical support (where available)
- Charging stations for cellular devices, radios, and computers

CRCs adhere to all existing local, county, state or federal public health orders and will have personal protective equipment on site and available to customers if needed. Local emergency management and community-based organizations will be notified of CRCs as appropriate and with advanced notice, generally three days prior to the event, when possible.
CRC activation timing, protocols, and locations are discussed with area emergency management and community-based organizations during emergency management workshops and tabletop exercises.

Figure 17: Example Temporary CRC

Depending on the needs of its public safety partners, CRC locations may be pre-identified. However, this is not always the case. For instance, in 2023 Pacific Power, together with its partners, determined that the need for and location of a CRC should be dependent on a PSPS area and community needs. As a result, it was decided that a CRC, if needed, should be activated in close coordination with public safety partners during a PSPS event. Pacific Power intends to continue collaborating with public safety partners to evaluate its approach to CRC activation and adapt its practices accordingly.

8.6 Re-Energization

As described in Section 7.1 above, local conditions are continually monitored during a PSPS 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.

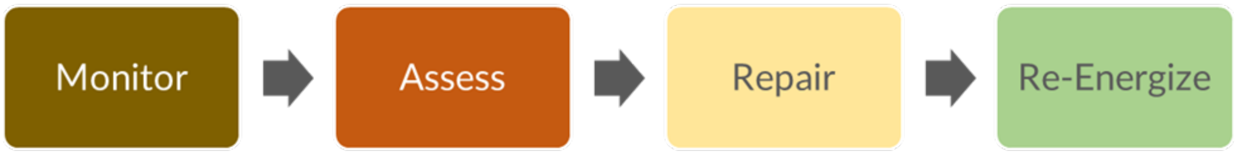


Figure 18: General Re-Energization Process

Once the local and forecasted conditions are favorable to re-energize and no new risk(s) have been identified, field personnel begin assessing the de-energized circuits generally through ground or air patrols. Power lines that have been de-energized during a PSPS event have been exposed to strong winds with 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 re-energizing 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 re-energization (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 and 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) de-energized 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 progress, instead of waiting for the assessment of the entire impacted area to complete. While not to scale or representative of an actual event, this concept is visually depicted in below.

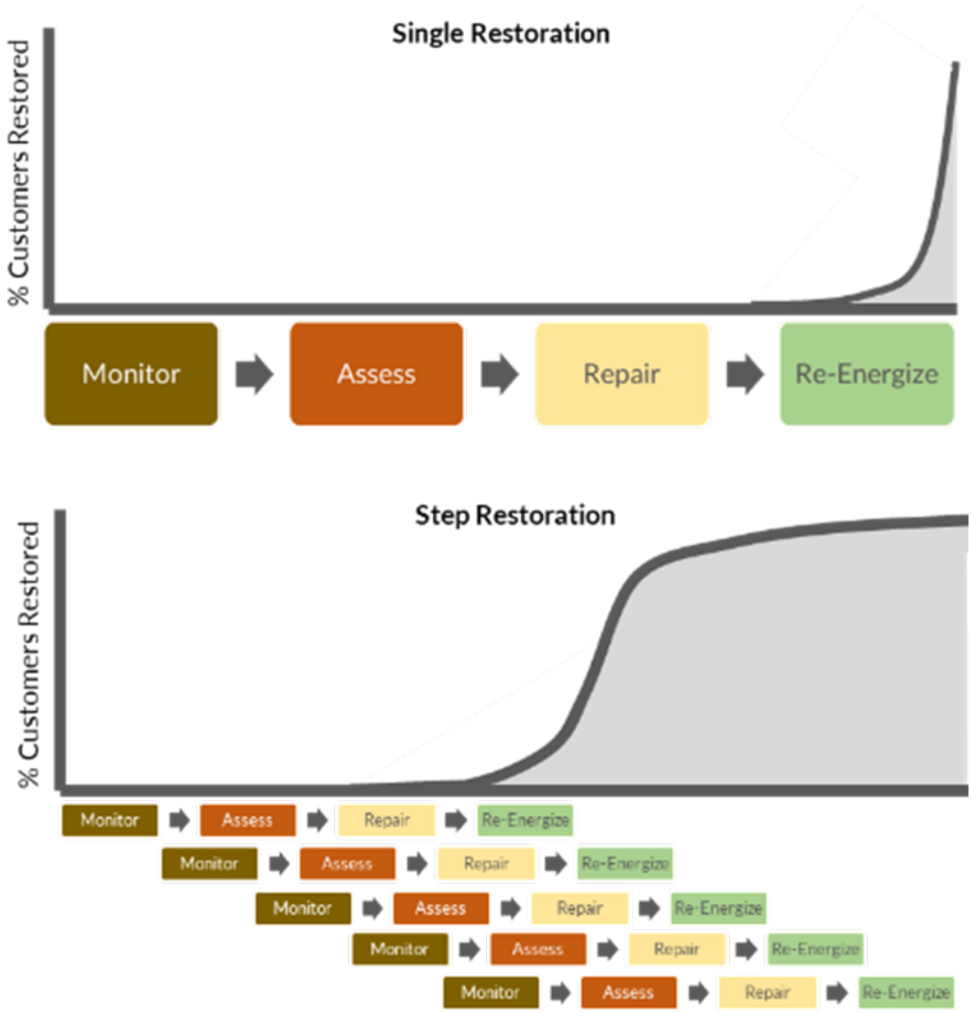


Figure 19: Visual Depiction of Step Restoration

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 re-energized, and the date and time of re-energization is logged. Once service is restored to all customers impacted by the PSPS event, the event concludes.

8.7 Experience

Pacific Power plans to continuously improve all aspects of its emergency management practices. From its experience to date, it has identified four key opportunities for improvement to its Public Safety Power Shutoff Program moving forward.

- Broaden public outreach and engagement. Pacific Power plans to expand its communication and overall preparedness as appropriate to ensure adequate public outreach and engagement regarding PSPS and wildfire safety.

- Strategize community resource center locations. One CRC was stood up during the 2022 PSPS event in Cedar City with minimal customer interest. Pacific Power will continue to emphasize CRC planning during workshops and tabletop exercises. During events, it will work with local public safety partners to better identify the needs of communities impacted.

- Streamline GIS and information sources. Due to the dynamic nature of a PSPS event, there is a need to manually update multiple sources of information and GIS layers among various internal platforms. Pacific Power plans to leverage its 2023 public safety partner coordination plan to streamline and better align GIS layers and information sources to communicate information quickly. For instance, Pacific Power is currently working to develop a secure, web-based public safety partner portal where critical information can be shared with its partners during a PSPS event.

- Internal communication and coordination. Most documents, communication protocols, and processes have worked well. Nevertheless, there is still an opportunity to build out new tracking tools, documents, and training within the existing response structure. To that end, a novel tracking tool has been developed and Pacific Power has begun to look at building out additional situational awareness tools.

9. Public Safety Partner Coordination Strategy

Pacific Power participates in public safety partner meetings and utility workshop sessions during the calendar year; meetings are attended throughout the service territory and include monthly, quarterly, and annual emergency management partner and pre- and post-fire season collaboration meetings with local, state, and federal fire officials. Pacific Power's 2022 emergency training plan includes one PSPS exercise to be held in Yakima County. The company will incorporate lessons learned from workshops attended to further compare and refine plans, streamline processes, and confirm capabilities with local public safety partners located in the designated FHCA.

Tabletop Exercises

Pacific Power, in coordination with public safety partners, conducts annual exercises throughout its service territory to support awareness, PSPS planning, and overall collaborative wildfire safety and PSPS preparedness within PSPS Zones. The exercises ensure public and private sector coordination during system events, validate communication protocols, and verify capability to support communities during extreme risk events through mitigation actions including the deployment of community resource centers. Identification of critical infrastructure at the county level is included as part of the exercise to better inform restoration planning and notifications.

Pacific Power solicits feedback from exercise sessions and real-world events involving wildfire safety and public safety power shutoffs. Areas found for improvement are added to a comprehensive improvement plan which is shared with the appropriate public safety partners. A webinar, prominently displayed on the wildfire safety section of the Pacific Power website, provides additional information on the company PSPS practices

10. Education and Awareness Strategy

Pacific Power provides wildfire safety and preparedness and Public Safety Power Shutoff (PSPS) public outreach and education through a variety of channels. Communication efforts on these topics target the company's entire customer base. The following descriptions of engagement and outreach methods are not meant to be an exhaustive list but represent the baseline efforts that are planned for 2023. Pacific Power maintains an education and awareness strategy that is flexible and allows for a dynamic communications plan, 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.

Media Campaign

For the past several years, the company has deployed some form of paid media campaign to raise awareness and action on wildfire safety. The company expanded this effort in 2023 as part of the broader community engagement strategy deploying digital, and social media ads, as a minimum, to promote wildfire safety and preparedness.
Prior to the 2023 paid media campaign launch, Pacific Power engaged Public Safety Partners, and Community-Based Organizations for messaging input and to ascertain if there are additional campaign element opportunities outside of traditional paid advertising channels. Based on feedback the ad campaign was delivered in English and Spanish during the wildfire season months. Following the campaign, the company will evaluate customer impacts determine additional messaging and engagement opportunities ahead of the 2024 campaign.

Supporting Collateral and Media Outreach

Pacific Power has developed a number of print and digital collateral pieces that includes 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. 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.

Each year prior to fire season, Pacific Power distributes updated wildfire safety information and information on the company's wildfire mitigation plan to press outlets across its service area as an additional low-cost outreach method. Before and during previous wildfire seasons, Pacific Power Public Information Officers proactively engage with media on company wildfire mitigation efforts and wildfire safety information. For 2023, the company provided additional information to news reporters on topics, such as wildfire mitigation.

Customer Service Training

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 translation service that translates communications in real-time over the phone in Chinese, Cantonese, Mandarin, Tagalog, Vietnamese and a variety of other languages and dialects.

Figure 20: Overview of Ad Campaign Methodology

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

Webpage

The Pacific Power website provides robust and comprehensive information on company wildfire mitigation programs, general wildfire safety, PSPS information and more.

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 for the public to create an emergency plan for their family along with a Wildfire Safety Checklist are easily accessible. The Wildfire Safety webpages include a link to the Pacific Power Wildfire Protection Plan for reading, 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.

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 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 them with general situational awareness information, such as an interactive map of the PSPS areas and a seven-day forecasting table that provides insight into if the company is considering a PSPS for public safety and what areas might be affected.

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.

Webinars

Once a year, Pacific Power develops a webinar to provide an overview of the company's wildfire mitigation program and strategies. Amongst 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 webinars continue to provide transparency and insight into the operational practices of Pacific Power's Wildfire Protection Planning and typically leave room for questions and answers during the webinar's initial live stream. The company intends to replicate this information format in a live setting during 2024 for its wildfire safety and preparedness forums.

Medical Baseline / Access and Functional Needs Population Engagement

Pacific Power allows customers to either self-identify as having access and functional needs (AFN) or apply for consideration as a medical baseline customer which. A special designation is then added to these customer accounts in the company's system or record which is used to manage notifications pertinent to potential or existing PSPS events, available programs, and overall wildfire safety.

11. Industry Collaboration

Industry collaboration is another component of Pacific Power's Wildfire Protection Plan. 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),[16] 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.

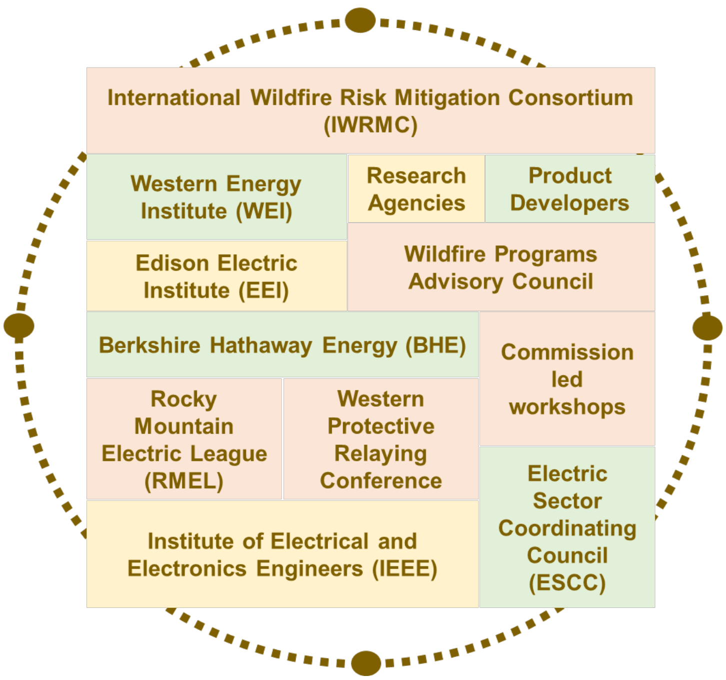


Figure 21: Key Industry Collaboration Channels

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 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. 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,

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

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.

12. Plan Monitoring and Evolution

Pacific Power's 2023 Washington Wildfire mitigation plan describes the additional investments and programs needed to construct, maintain and operate electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire. However, the strategies embodied in this plan are evolving and are subject to change. Pacific Power will regularly evaluate and monitor the effectiveness of this plan. As new analyses, technologies, practices, network changes, grant opportunities for cost sharing, environmental influence or risks are identified, changes to address them may be incorporated into future iterations of the plan. Additionally, as new information or requirements are identified through formal rulemaking or collaboration with regulators and stakeholders, plan elements or scope may change.