ITEM NO. RM1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 18, 2022

REGULAR ___ **CONSENT** ___ **RULEMAKING** __X__ **EFFECTIVE DATE** __N/A__

DATE: January 11, 2022

TO: Public Utility Commission

FROM: Lori Koho

THROUGH: Bryan Conway **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. AR 638)
Request to open formal rulemaking for Phase II wildfire mitigation rules.

STAFF RECOMMENDATION:

Open a formal rulemaking and issue a proposed notice of rulemaking to amend and adopt rules addressing risk-based Wildfire Mitigation Plans consistent with Senate Bill (SB) 762 (2021), as set forth in Attachment A.

DISCUSSION:

Issue

Whether the Oregon Public Utility Commission (Commission) should open a formal rulemaking and issue a notice of proposed rulemaking to amend and adopt rules addressing risk-based Wildfire Mitigation Plans consistent with Oregon SB 762, as set forth in Attachment A.

Applicable Rule or Law

Per ORS 756.040, the Commission has authority to supervise and regulate every public utility in Oregon, and to do all things necessary and convenient in the exercise of such power and jurisdiction. Under ORS 756.060, the Commission may adopt reasonable and proper rules relative to all statutes administered by the Commission.

ORS 757.035(1) provides the Commission with the authority to adopt safety rules and regulations

> …in such manner as to protect and safeguard the health and safety of all employees, customers and the public, and to this end to adopt and prescribe the installation, use, maintenance and operation of appropriate safety or other devices, or appliances, to establish or adopt standards of construction or equipment, and to require the performance of any other act which seems to the commission necessary or proper for the protection of the health or safety of all employees, customers or the public.

Executive Order 20-04 (EO 20-04), Section 5(B)(4) directs the Commission to evaluate electric companies' risk-based wildfire protection plans and planned activities to protect public safety, reduce risks to utility customers, and promote energy system resilience in the face of increased wildfire frequency and severity, and in consideration of the recommendations made by the Governor's Council on Wildfire Response 2019 Report and Recommendations.

Senate Bill 762 (2021) is a comprehensive bill establishing standards for Wildfire Protection Plans for electric utilities, statewide risk analysis, and wildfire smoke mitigation. Relevant sections of SB 762 are discussed below. Sections 1 through 6(b) of SB 762 are specific to requirements to be included in electric utility Wildfire Protection Plans (Plans) and the requirement for the Commission to promulgate rules related to the requirements of those plans. The bill also set December 31, 2021, as the deadline for investor-owned utilities (IOU) to file plans with the Commission.

<u>Analysis</u>

Background
On August 25, 2020, the Commission opened an informal phase for rulemaking related to Wildfire Protection plans (Docket Number AR 638).[1] This action was spurred, in part, by the Governor's Executive Order 20-04. Subsequent to the opening of this rulemaking proceeding and EO 20-04, the Oregon legislature passed SB 762, which set forth specific directives for the Commission related to electric wildfire plans.

In order to have near-term protections in place and gather vital information during the 2021 wildfire season, the Commission adopted temporary rules in Order No. 21-167 governing Public Safety Power Shutoff (PSPS) protocols and ignition reporting requirements. Those rules expired on November 24, 2021.

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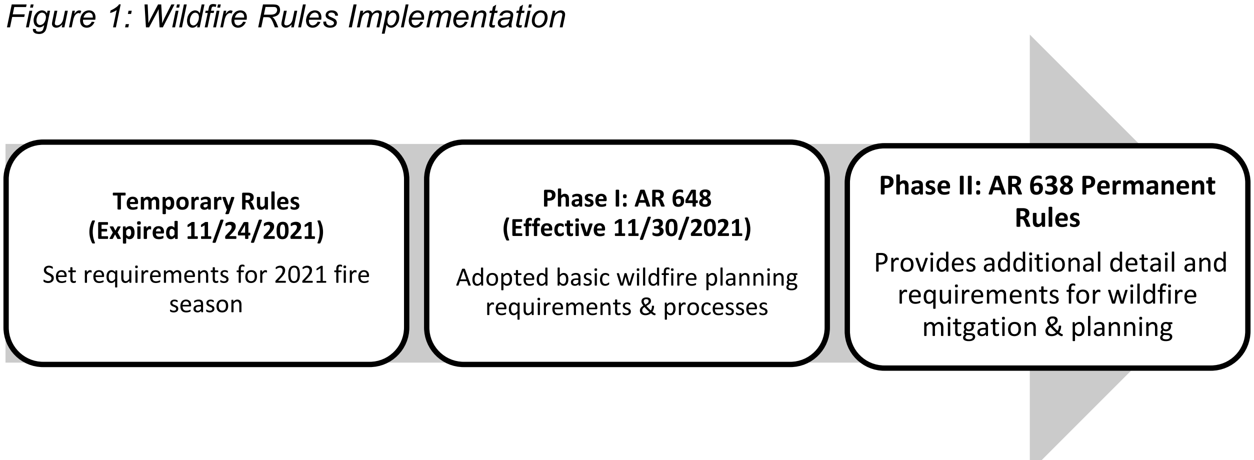
[1] *In re Rulemaking Regarding Electric Utility Wildfire Mitigation Plans*, OPUC Docket No. AR 638, Order No. 20-272 (Aug. 26, 2020).

A separate rulemaking proceeding, AR 648, was opened August 31, 2021, to adopt permanent rules addressing certain procedural and filing requirements in SB 762. These rules require utilities to submit wildfire protection plans no later than December 31, 2021. In Order No. 21-440, the Commission adopted permanent rules. Staff is proposing to amend certain existing Division 300 rules as well as to supplement the rules with additional requirements. Staff is also proposing amendments to Division 24 safety rules as well as adopting a permanent rule for fire related incident reporting rules. Staff's proposed rules and amendments to current rules provide more clarity to what is required in utility Wildfire Protection Plans as well as updates to processes and procedures utilities must implement to improve utility system resilience during a time of changing wildfire risks.

As set forth below, Staff has engaged with stakeholders in the development of its proposed permanent rules (Attachment A), which have been refined from its initial draft rules (Attachment B) based on stakeholder feedback through the informal rulemaking process.

Figure 1: Wildfire Rules Implementation



Phase II: AR 638 Permanent Rules Procedural Background

In the development of the proposed rules in this case, Staff conducted a number of workshops addressing specific topics of the rulemaking. The topical groups included:

- Vegetation Management and System Hardening
- Risk Analysis
- Public Safety Power Shut-off
- Community Engagement

Stakeholders were invited to file written comments based on discussions during those initial workshops. Comments were received from:

- Portland General Electric (PGE)
- Joint Utilities (PGE, PacifiCorp, and Idaho Power)
- Central Lincoln People's Utility District (CLPUD) and Tillamook People's Utility District (TPUD)

Based on comments received and following internal discussion, Staff reviewed the scope of the Phase II rules and concluded that much of the detail in the temporary rules for PSPS and Community Engagement was overly prescriptive.

As such, Staff filed a revised schedule for permanent rules on August 19, 2021, and then held a workshop on August 23, 2021, to discuss the schedule and revised scope.

Staff filed its initial draft rules on September 29, 2021. Those rules were discussed at a workshop with stakeholders on October 11, 2021. The deadline for stakeholder comments was November 19, 2021. Staff received written comments from the following stakeholders:

- Idaho Power Company (Idaho Power)
- PacifiCorp
- Portland General Electric (PGE)
- Rogue Climate
- International Brotherhood of Electrical Workers (IBEW) Local 125
- Oregon Telecommunications Association (OCTA)
- Jim and Fuji Kreider (Kreider)
- Urbint
- Oregon Joint Use Association (OJUA)
- Oregon Trail Electric Cooperative (OTEC)
- Cellular Telecommunications Industry Association (CTIA)
- Consumers Power Inc. (CPI)
- Oregon People's Utility District Association (OPUDA)
- Oregon Rural Electric Cooperative Association (ORECA)
- Oregon Municipal Electric Utilities Association & Eugene Water and Electric Board (OMEU & EWEB)

Based on stakeholder feedback and additional internal discussions, Staff made a number of changes to its initial draft rules. Those changes are reflected in Staff's proposed permanent rules in this case (Attachment A), as summarized below. In the following discussion, unless otherwise stated, Staff is referring to comments made on its initial draft rules filed on September 29, 2021. The discussion below is related to substantive requirements for proposed permanent rules. Some rules required ministerial changes (such as capitalization, renumbering, etc.), which are not substantively discussed but are reflected in Attachment A.

Summary of Proposed Rules and Comments

Division 300

OAR 860-300-0001
Scope and Applicability of Rules

Staff does not propose substantive changes to OAR 860-300-0001, which was adopted in AR 648, other than to reflect the terminology change from “Wildfire Protection Plan” to “Wildfire Mitigation Plan,” consistent with the terminology used in the remainder of the Division 300 rules.

OAR 860-300-0002
Definitions for this Division

This proposed rule includes definitions necessary to implement Division 300 requirements related to Wildfire Mitigation Plans.

While developing the temporary rules, many stakeholders commented on what should be included as a critical facility. OCTA and OTA both provided comments that telecommunications infrastructure is key and should always be identified as a critical facility. Based on Staff’s experiences and observations during the 2020 Labor Day fires and the February 2021 ice storm, the ability to communicate was second or equal in urgency to a power loss itself. Consequently, Staff was persuaded to include telecommunications facilities and infrastructure as a critical facility. This is the only change made from Staff’s initial draft rules for this section.

Rogue Climate requested that the rules identify vulnerable or functional needs communities. Staff did not choose to identify vulnerable or functional needs communities in the rules over concerns that defining these terms would be overly prescriptive and could have unintended consequences given that the utility may not be positioned to provide or coordinate certain services. As such, these rules contemplate utility partnership with local jurisdictions to help provide power to priority areas or community centers where possible.

OAR 860-300-0003
Public Utility Wildfire Mitigation Plan Filing Requirements

As stated above, filing requirements for Wildfire Mitigation Plans were adopted as part of AR 648, and currently reside in OAR 860-300-0002. Staff's draft permanent rules move these requirements to OAR 860-300-0003, for organizational purposes, add reference points to other applicable rules, and amends subsection (2) to reflect that the first Wildfire Mitigation Plans have been filed and to clarify what must be included in each subsequent filing.

PGE requests clarifying language that the Wildfire Mitigated Plan filed by December 31 of a given year apply to a fire season two years ahead, rather than the following year. Staff declined to make this change. PGE's request that rules apply to a fire season two years ahead is unnecessary. A utility's plan will always be a multi-year plan with dates in the future for completion. The Commission should retain the option to decide if the utility's proposed timeline is appropriate.

Other stakeholders commented that by the time these rules are released, the December 31, 2021, deadline will have passed. Stakeholder's observations regarding the initial due date is correct and the Staff's proposed permanent rule reflects this reality.

OAR 860-300-0004
Risk Analysis

This rule establishes standards Public Utilities must follow to identify areas within their service territories that are High Fire Risk Zones. The rule is not prescriptive in stating which models or sources of information a utility must use, but instead requires the utility identify sources of information and models used in the plan.

CPI commented that the standards in this section, while applying only to IOUs, may be viewed as a best practice for all electric utilities in the state and the requirements may be onerous for a small consumer owned utility (COU). CPI observed that if not followed by a COU then they may be open to liability for failing to follow these best practices. Staff agrees with CPI's comment, and notes that many standards in the rule may be considered best practices. In many cases, the IOUs may be subject to higher standards than those required of the COUs.

PGE commented that it believes climate is not a baseline risk because it is dynamic and not static, and therefore, requested that "climate" be removed as an example of a baseline wildfire risk. Staff declined to make PGE's requested change. There are aspects of climate change that are considered baseline risk. The rule that follows, OAR 860-300-0004(B), discusses seasonal wildfire risk that are more dynamic.

OAR 860-300-0005
Wildfire Mitigation Plan Engagement Strategies

This rule establishes minimum expectations for the Public Utility's engagement with communities in its service territory. Community input must inform the utilities' plans for developing outreach methodologies in the event of a fire or Public Safety Power Shutoff (PSPS). The rule also outlines minimum elements that must be included in an education and awareness strategy.

CPI expressed concern that the engagement strategies outlined in this section would be a significant burden. CPI explained that its territory covers multiple counties and local jurisdictions, and stated that local public safety partners may be difficult to engage outside of an emergency. Both the utility and the local public safety partners are challenged to engage in proactive community engagement. Staff notes that this rule only applies to IOUs and remains a best practice in light of community expectations of utilities.

PGE requests clarification regarding "developed in coordination with Public Safety Partners." PGE also requests changing (c) to reading "Information on emergency kits/plans/and checklists," and (e) to read "Information and preparedness media platforms to inform the public." Idaho Power also seeks clarity on (c), (e), and (f). It questions if Staff's intent is for the utility to provide emergency kits to customers.

Staff finds the rule as drafted to be sufficient and clear. Training and education imply different activities than "information." Information can be interpreted as bill-stuffers or emails to customers. Utilities must be more actively involved in customer engagement. It is still the utility's responsibility to identify what methods it will use. Staff's intent with the rule stating these strategies must be coordinated with Public Safety Partners is to emphasize the need for consistent messaging and identifying ways the utility can optimize its efforts.

In response to Idaho Power's question about emergency kits, Staff clarifies that the intent is not that a utility should provide emergency kits to its customers. Emergency kits are unique to the needs of the individual, household, business, etc. The utility can provide direction to information, participate in community preparedness events, host events, etc.

In response to Idaho Power's comment regarding Education and Awareness Strategy requirement (f) related to the "frequency of preparedness" language that was originally included, Staff appreciates Idaho Power's comment regarding the need to clarify, and has amended the language to make clear that the requirement is related to the frequency of outreach to inform the public.

OAR 860-300-0006
Communications Requirements Prior, During, and After a Public Safety Power Shutoff

This rule provides requirements for notification a Public Utility must provide to Public Safety Partners, Operators of Critical Facilities, and its customers in the event of a PSPS. The rule also lays out the time frame and information that is to be provided during those notifications. The rule recognizes that each situation is different. Staff understands that it may not be possible to comply with the exact timelines in the rule but the Public Utility is expected to make the best effort possible.

OCTA and CTIA have both commented that telecommunication providers need as much detailed information as possible related to PSPS. As currently written, the draft rules have no requirement for the Public Utility to provide Geographic Information System Mapping (GIS) files or access to real time geographic information pertaining to the event OCTA and CTIA note that this detailed information will allow them to identify specific facilities that might be impacted by the PSPS. An example would the ability to stage additional generators or batteries for a cell tower.

Staff appreciates the participation of OCTA and CTIA in this proceeding. Oregon's recent ice storms and wildfires have drawn attention to the criticality of communications systems. Staff is confident the relationship between the telecommunications Operators and the Commission, as its Emergency Support Function (ESF) partner, will become more robust as preparation and response system mature. Staff is persuaded by the comments from OCTA and CTIA. Staff has added special considerations for telecommunications providers to its Proposed Draft Rules.

OAR 860-300-0007
Ongoing Informational Requirements for Public Safety Power Shutoffs

This rule directs Public Utilities to provide real-time information on details of PSPS locations, including estimation of any de-energizations and estimates of re-energization. This information must be posted on the Public Utility's website. The information must be in a format that can be shared with Public Safety Partner GIS platforms.

OAR 860-300-0008
Reporting Requirements for Public Safety Power Shutoffs

This rule requires Public Utilities file annual reports on lessons learned during the fire season if the utility had to implement a PSPS.

OAR 860-300-0009
Cost Recovery

This rule remains identical to the rule adopted in AR 648, with the exception of moving it from OAR 860-300-0003 to -0009, for organizational purposes.

Idaho Power and PGE both requested clarification on cost recovery. In its written comments on May 3, 2021, Rogue Climate commented that utilities should not pass costs on to customers for upgrading utility infrastructure to withstand increased wildfire danger.

Staff declined to make changes to this rule. The rule mirrors statutory requirements, and otherwise allows the Commission to maintain discretion and flexibility in designing cost recovery as appropriate for each utility.

Division 024 Safety Rules

OAR 890-024-0001
Definitions for Safety Standards

Staff proposed four new definitions for this Division. “High Fire Risk Zones,” “Joint Inspection,” “Occupant,” and “Owner.” Several stakeholders provided comments on the definitions that were primarily stylistic. Multiple stakeholders objected to the inclusion of “Joint Inspection” in the definitions over concerns that any requirements of joint inspection should not be part of this rulemaking proceeding. Staff adopted suggestions that improved clarity of the definitions. Staff’s response to the inclusion of Joint Inspections in this proceeding is discussed below.

OAR 890-024-0005
Maps and Records

Multiple electric utility Operators questioned Staff’s original proposed rule that utilities file maps with the Commission on April 1 of each year with the most recently identified High Fire Risk Zones. They noted that this would be duplicative of what would have been filed in the latest Wildfire Mitigation Plan. Stakeholders also objected to the statement that maps “shall be in a form satisfactory to the Commission” due to concerns that the requirement lacks specificity.

Staff appreciates Stakeholders’ desires to minimizing regulatory burden. Staff’s intent is not to substantively change the existing process. The intent is to capture in rule that any maps requested must include identified High Fire Risk Zones. The requirement to provide maps in a form satisfactory to Commission Staff has been in place for many years. The rule is purposely written that way to allow for changes in technology or allowing a format that meets the needs of the requestor. Safety Staff requires as much detail as possible, which might include pole numbers, date last inspected, etc. Other Commission Staff may only need the basic maps of specific circuits.

Many Operators are now using some version of GIS software. Some are still using paper maps. The rule allows Staff to work with each Operator to share maps as accurately and efficiently as possible.

Staff's proposed amendment to the rule does not necessarily necessitate a separate filing, but does request information be current with High Fire Risk Zones. As information changes, Staff finds it necessary to have the most updated maps.

OAR 860-024-0011
Inspections of Electric Supply and Communication Facilities

Staff's proposed amendments to OAR 860-024-0011(1)(b)(B) seek to clarify what must be included, at a minimum, for detailed inspections. Staff's amendment adds the requirement that detailed inspections include pole test and treat programs for pole owners, and that shorter intervals of inspection may be required in High Fire Risk Zones.

Multiple stakeholders objected to Staff's proposed amendments that would provide additional focus to onsite inspections of facilities including physical inspections as well as pole test and treat programs.

Staff's proposed amendments are based on facility failures observed in this and other states that may have been mitigated by basic "hands on" inspections. Other tools and technology developments may assist and accelerate inspections. Some technologies provide details facility owners would not have been able to obtain in the past. However, these technologies do not replace the skill of a qualified electrical worker in assessing the conditions of the facilities on site. Staff's initial draft rules required a pole test and treat program for all facility owners. In response to stakeholder concerns, the final proposed rule requires pole test and treat programs of pole owners only.

Staff's proposed amendments to Subsection (2)(b) are in response to PGE's comment that electric supply Operators make best efforts to notify Operators of any changes to the established annual geographic designation within 60 days of the start of the next year's inspection. Staff finds that flexibility for High Fire Risk Zone notification is needed.

OAR 860-024-0012
Prioritization of Repairs by Operators of Electric Supply Facilities and Operators of Communication Facilities.

This section of the rules defines the timeline an Operator has to correct violations after discovery. The rule currently allows operators to defer corrections no longer than ten years based on specific conditions. Staff's initial draft rules eliminated the allowance to defer corrections after December 31, 2027. Many stakeholders objected to eliminating the deferral allowance. One stakeholder commented that it is already difficult to complete repairs within the two-year standard. Another spoke to situations where it is required to coordinate with public works projects or have permitting issues.

Some stakeholders commented that this provision has allowed them flexibility coordinating work and crews and eliminating the ability to defer corrections would increase costs.

Staff appreciates this may be interpreted as a large change to the safety rules. The original safety rules were developed for all facilities to be inspected every ten years with violations corrected no later than two years after discovery. In practice, deferrals have become incredibly commonplace. Operator inspection correction programs should not be designed with the expectation that deferrals are the standard way to manage workload. Staff's observation is the deferral process has been abused by many operators.

Staff would like to emphasize that facility Owners and Operators are in the fifteenth year of their inspection correction programs if they are in compliance with Commission rules. Theoretically, the number of violations in the field should be declining. Staff appreciates that the system is dynamic, facilities age and degrade over time, and new facilities are attached. However, at this point, violations that may have existed prior to the implementation of the Division 24 rules should have been corrected, new installations should be code compliant, and the only new possible violations would be facility aging or damage. The need for deferrals should be minimal except for certain conditions.

The example of coordinating corrections with local jurisdictions, road widening, urban renewal, permitting, etc. is a valid reason to request a deferral. The utility has no control over the timing of those projects.

Based on what Staff believes are reasonable justifications to request a deferral, Staff modified its initial draft rules to allow for specific conditions to justify requesting a deferral to correct a violation longer than two years from discovery.

OAR 860-024-0016
Minimum Vegetation Clearance Requirements

This rule addresses minimum vegetation clearance requirements. Staff's approach in drafting amendments to the current rules was to focus on processes, procedures, conditions, and timelines, rather than on the actual required clearances. The rules have always provided the guidance of a minimum clearance. The Operators are expected to understand the system and vegetation in the proximity of their facilities and to run a program that maintains a safe system. An Operator may determine it has to maintain clearances substantially greater than what is in rule to mitigate other risks in the area of its facilities.

Two of Staff's proposed amendments garnered the most comments from stakeholders. Staff originally proposed amending subsection (3) to require all electric utilities to operate a three-year trim cycle unless they provided Commission Staff with an alternative trim cycle program that demonstrated clearances were being maintained. The other was an amendment to subsection (5) to add "adverse weather and wind conditions" to the conditions operators must consider when setting trim cycles and clearance distances.

Upon further reflection and discussion, Staff agrees with stakeholders' comments on subsection (3) that dictating a default three-year trim cycle is not appropriate. Staff reworded the proposed amendment clarifying the expectation that electric utilities have a formal vegetation management plan designed to meet the requirements of the rule. The rule also states the Commission may dictate an alternative trim cycle if the Operator's program does not result in maintaining required clearances.

Staff disagrees with stakeholders' other concerns and believes the proposed amendments enhance the expectations of any vegetation management program.

OAR 860-024-0018
High Fire Risk Zones (HFRZ) Safety Standards

This rule is new in the Division 24 rules with incremental requirements in High Fire Risk Zones. The rule seeks to set forth specific safety standards for High Fire Risk Zones. Most of the comments received on Staff's Proposed Draft rules focused on this new section.

Many stakeholders objected to Staff's focus on in-person and onsite inspections that include practical tests. "Practical tests" is a term of art in the industry that currently includes sounding poles, testing continuity of grounding, etc. There was also concern that the rule was eliminating consideration of new technologies being developed. Currently the focus is on the use of drones, infrared technology, etc.

Some stakeholders interpreted the inspections required in the High Risk Fire Zone as doubling up on the normal inspection requirements or that they would be making two trips in a year for an inspection.

Most comments were in response to Staff's proposal to require joint inspections of facilities. Stakeholders commented that there is no improvement to safety, it is difficult to coordinate, and some attachers are non-responsive when violations are identified that relate to the attacher's facilities. Some stakeholders also suggested that many of these requirements, particularly joint inspections, are out of scope for wildfire mitigation. Telecommunication providers asserted there is already a shortage of inspectors and this would require more resources; that pilot programs have not been successful and have actually resulted in higher costs for telecommunication operators; and joint inspections, if on the cycle of the electric utility, would push them out of compliance on their already established schedules. PacifiCorp was the sole stakeholder in support of joint inspections. PacifiCorp is also in support of joint corrections.

Stakeholders also objected to OAR 860-024-0018(8) requiring violations identified by the Operator of an electric facility be corrected no later than 180 days after discovery regardless of pole ownership.

Staff recognizes these new draft proposed rules represent a large shift in approach to operations and maintenance. Staff disagrees that these requirements are overly burdensome or that they do not promote safety. Wildfire risks are forcing rapid evolution of industry standards and it is the Commission's duty to provide minimum standards. Staff's proposals are driven by observations made during Staff's compliance inspections as well as learnings from analysis of other recent wildfires.

Regarding comments made by telecommunications providers and others that its facilities play no role in wildfires, Staff can provide reference to at least two fires where telecommunications utilities were implicated in the cause of the fires. While the utilities did not admit fault, San Diego Gas & Electric and Cox Communications agreed to pay $17 million to settle claims that their lack of maintenance led to the Witch Creek, Guijito, and Rice Canyon fires. Investigators said a Cox lashing wire came loose in high winds and caused arcing when it came in contact with an SDG&E power line.[2]

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[2] https://wildfiretoday.com/2009/10/30/san-diego-power-company-pays-14m-to-state-for-starting-huge-fires-in-2007/.

The California Public Utilities Commission reached a settlement of $12 million with Sprint, Verizon, and AT&T after investigating the cause of the Malibu Canyon fire.[3] The investigation found the wireless antennas attached to a utility pole exceeded the mechanical strength of the pole.

In Oregon, telecommunication companies own a number of poles to which electric utilities are attached. PacifiCorp reports that in its service territory, it is attached to over 400 utility poles owned by telecommunication utilities that have been identified as unsafe. Staff has observed telecommunication utility owned poles marked by linemen as too dangerous to climb. Accordingly, it is clear to Staff that the installation, operation, and maintenance of telecommunication facilities is key in wildfire safety.

Staff maintains that the requirement of practical tests is critical, but finds that defining "practical tests" would be overly prescriptive. Allowing the industry to dictate practical tests allows for evolution over time as technology and circumstances change. An exception is Staff requiring pole Owners to implement pole test and treat programs. The industry and qualified electrical workers are trained in specific things to do or perform on site. These basic hands-on assessments are difficult to replace. These onsite inspections also ensure the utility is evaluating access to facilities in the event of emergencies. Fire fighters also need access, preferably vehicle, but an alternative can be a reasonable landing place for air drops, for protecting utility assets during fires.

Staff agrees that the initially circulated draft rules appeared to limit or discredit the value of drones and incremental technology. In response to that, language was added recognizing the value of those incremental tools. In many cases, those tools can identify hazards more rapidly than can be found otherwise. Staff believes these are excellent incremental tools to improve safety. They cannot be expected to replace all existing all inspection methods and tools.

A more comprehensive list of stakeholder comments related to joint inspections and Staff's responses are included in Attachment C.

Attachment D contains photos of a small sample of conditions that Staff have found during inspections. In many situations, a condition has been identified during the Operator or pole Owner's inspection that has not been corrected in the two years required by rule. Sometimes these conditions are not corrected until Staff identifies them or a member of the public complains.

[3] https://archive.kpcc.org/blogs/environment/2012/09/13/9969/sprint-verizon-t-sign-12-million-settlement-over-2/.

The essence of the examples in Attachment D and Staff's response to the many objections above and in Attachment C is to illustrate Staff's rules are addressing an observed and documented safety issue.

There is also a sentiment among some stakeholders that Staff is more critical of electric Operators and should focus more on telecommunications Operators in its inspections. The implication is that telecommunication Operators would be more likely to comply with Commission rules if Staff was more aggressive in its enforcement. Staff disagrees that its approach is more favorable to telecommunications utilities, and regardless, safety should not be dependent on Staff's inspections.

Pole Owners and Occupants are all responsible for safe facilities and must jointly agree on violations and then must correct them in an accelerated timeline in the High Fire Risk Zones. If there isn't agreement, the violations must still be corrected on the accelerated timeline. The Safety rules do not address issues of cost recovery or relationship of parties. This is a fundamental safety issue.

If cost recovery for corrections is an issue, the utilities have the option of filing a complaint with the Commission. If joint use contracts have been a perceived barrier, utilities can bring these concerns to the Commission. If the Division 28 Joint Use Rules need to be amended to make duties of pole Owners and Occupants more explicit, then a separate proceeding may be appropriate.

However, Staff's proposed rules in this proceeding are based observations of conditions in the field and reviewing the records of pole Owners and Occupants that necessitate change due to wildfire circumstances.

General Comments

Rogue Climate reiterated comments it had provided previously in the docket, stating that "During a PSPS incident, there should be appropriate resources for high-risk community members to access life-saving electricity, whether it is being supplied with backup power resources or ensuring communities have access to emergency resiliency hubs." Rogue Climate further discusses the need for this rulemaking to address strategies for community resilience. Rogue Climate also pointed to rulemakings occurring in other agencies and the need to reconcile definitions and approaches.

Staff appreciates the position of Rogue Climate and understands the value and need for community resilience. The question is whether this should be a component of wildfire mitigation rules. It may be that investments in utility operations and infrastructure will improve community resilience and the utility can refer to multiple benefits in its plan.

Multiple system benefits may be a factor in prioritization of any proposed investments. At this time, Staff finds that its proposed rules represent a robust and comprehensive approach to wildfire mitigation. CPI commented that:

> Throughout these draft rules there are mandatory inspections, remediation actions, meetings, and coordinated activities that electric utilities must engage in with external stakeholders. These stakeholders include telecommunication companies, law enforcement, emergency management, local governments, and other entities. The rules do not include regulatory methods for an electric utility to compel these actions. The net effect is that electric utilities will fall short of these regulatory requirements unless every single identified stakeholder acts proactively, and in good faith, to meet all utility company requests without deviation. This is an unreasonable expectation that ignores the fact that other entities have their own operational priorities, funding issues, and organizational focuses. CPI believes the draft rules should make allowances through “safe harbor” language for utilities that make good faith efforts to follow the rules but are ignored, rebuffed, or stymied in their efforts to comply.

Staff disagrees with CPI’s “safe-harbor” comment. One of the goals of this rulemaking is to bring awareness of changing wildfire risks to Operators who have not yet internalized them. Many of Staff’s proposed rules remain prescriptive and raise the bar for minimum operational and system requirements at a time when the risks are far different and have greater impacts than when the rules were originally developed. These rules are intended to prompt Operators to review their own systems, risks, and community engagement. Some utilities have territories with minimal risk at this point in time**.** The Labor Day fires in 2020 were a wake-up call that what was normal in the past has to be continually re-evaluated. The risks are changing.

<u>Conclusion</u>

Staff recommends the Commission open a formal rulemaking to amend and adopt rules addressing risk-based Wildfire Mitigation Plans, as set forth in Attachment A.

PROPOSED COMMISSION MOTION:

Open a formal rulemaking and issue a proposed notice of rulemaking to amend and adopt rules addressing risk-based Wildfire Mitigation Plans consistent with SB 762, as set forth in Attachment A.

Division 300

860-300-0001
Scope and Applicability of Rules

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

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

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: ORS 756.040, ORS 757.035, ORS 757.039, ORS 757.649, ORS 759.030, ORS 759.040 & ORS 759.045

860-300-0002
Definitions for this Division

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

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

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

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

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

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

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

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

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

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

Statutory/Other Authority:

Statutes/Other Implemented:

860-300-0003~~2~~
Public Utility Wildfire Mitigation Plan Filing Requirements

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

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

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

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

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

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

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

(e) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure, including a PSPS communication strategy consistent with OAR 860-300-0005 through 860-300-0006.

(f) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season, consistent with OAR 860-300-0005 and OAR 860-300-0006.

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

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

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

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

(2) A Public Utility's initial Wildfire Mitigation Plan was filed in 2021. Wildfire Mitigation Plans must be updated annually and filed with the Commission no later than December 31 of each year. Public Utilities are required to provide a plan supplement explaining any material deviations from the applicable Wildfire Mitigation Plan acknowledged by the Commission~~A Public Utility's initial Wildfire Protection Plan must be filed no later than December 31, 2021 per section 5, chapter 592, Oregon Laws 2021. Subsequent Wildfire Protection Plans must be updated annually and filed with the Commission no later than December 15th~~.

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

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

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: 2021 Senate Bill 762, ORS 756.040, ORS 756.105, ORS 757.035 & ORS 757.649

860-300-0004
Risk Analysis

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

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

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

(B) Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year. Examples include cumulative precipitation and fuel moisture content.

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

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

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

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

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

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

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

(A) Public Safety Power Shutoffs

(B) Vegetation Management,

(C) System Hardening,

(D) Investment decisions, and

(E) Operational decisions.

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0005
Wildfire Mitigation Plan Engagement Strategies

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

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

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

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

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

(2) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Education and Awareness Strategy. The Education and Awareness Strategy must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities. The Education and Awareness Strategy will include, at a minimum:

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

(b) A description of the Public Utility's wildfire mitigation strategy.

(c) Training on emergency kits/plans/checklists.

(d) Public Utility contact and website information.

(e) Education and preparedness media platforms to inform the public.

(f) Frequency of outreach to inform the public.

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

(A) Multiple languages prevalent to the area.

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

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

(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the Public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specified in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0006. The Coordination Strategy should include, at a minimum:

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

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0006
Communications Requirements Prior, During, and After a Public Safety Power Shutoff

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

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

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

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

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

(D) Number of customers impacted by PSPS;

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

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

(G) Notice of when re-energization begins and when re-energization is complete;

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

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

(A) Date and time PSPS will be executed;

(B) Estimated duration of PSPS;

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

(D) Notice of when re-energization begins and when re-energization is complete.

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

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

(2) When a Public Utility determines that a PSPS is likely to occur, the Public Utility must provide advance notice of the PSPS to customers via a PSPS web-based interface on the Public Utility's website and other media platforms, and may communicate PSPS information directly with customers consistent with 860-300-0006(b).

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

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

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

(C) Display on its website homepage a prominent link to access current information about the PSPS, consistent with OAR 860-300-0007, including a depiction of the boundary. The PSPS information must be easily readable and accessible from mobile devices.

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

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

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

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

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

(F) After initial notification, the Public Utility will provide, at a minimum, status updates at 24-hour intervals until service has been restored;

(G) Notice of when re-energization begins and when re-energization is complete.

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

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

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

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

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0007
Ongoing Informational Requirements for Public Safety Power Shutoffs

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

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

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

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

(5) The Public Utility will provide a comprehensive narrative of each subsection of this rule as part of its annual Wildfire Mitigation Plan.

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0008
Reporting Requirements for Public Safety Power Shutoffs

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-~~0003~~ 0009
Cost Recovery

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

Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: 2021 Senate Bill 762 & ORS 757.020

OAR 860-300-~~0004~~0010
Consumer-owned Utility Plans

Municipal electric utilities, people's utility districts organized under ORS chapter 261 that sell electricity, and electric cooperatives organized under ORS chapter 62 must file with the Commission a copy of its approved risk-based wildfire mitigation plan or plan update within 30 days of approval from its governing body.
Statutory/Other Authority: ORS 183, ORS 654, ORS 756, ORS 757 & ORS 759
Statutes/Other Implemented: 2021 Senate Bill 762 & ORS 757.035

Division 24

860-024-0000
Applicability of Division 24

(1) Unless otherwise noted, the rules in this division apply to every ~~operator~~Operator, as defined in OAR 860-024-0001.

(2) Upon request or its own motion, the Commission may waive any of the division 24 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 756.040, 757.035, 757.039, 757.649, 759.030, 759.040 & 759.045

860-024-0001
Definitions for Safety Standards

For purposes of this Division, except when a different scope is explicitly stated:

(1) “Commission Safety Rules,” as used in this section, mean the National Electric Safety Code (NESC), as modified or supplemented by the rules in OAR chapter 860, division 024.

(2) “Facility” means any of the following lines or pipelines including associated plant, systems, supporting and containing structures, equipment, apparatus, or appurtenances:

(a) A gas pipeline subject to ORS 757.039;

(b) A power line or electric supply line subject to ORS 757.035; or

(c) A telegraph, telephone, signal, or communication line subject to ORS 757.035.

(3) “Government ~~entity~~Entity” means a city, a county, a municipality, the state, or other political subdivision within Oregon.

(4) “High Fire Risk Zones” are geographic areas identified by Operators of electric facilities in their risk-based wildfire plans.

(5) “Joint Inspection” means an inspection of all equipment on any utility pole, structure, duct or conduit, owned by either the Owner or an Occupant(s).

(6~~4~~) “Material violation” means a violation that:

(a) Is reasonably expected to endanger life or property; or

(b) Poses a significant safety risk to any operator’s employees or a potential risk to the general public.

(7) “Occupant means any licensee, Government Entity, or other entity that constructs, operates, or maintains attachments on poles, structures or within conduits.

(~~5~~8) “Operator” means every person as defined in ORS 756.010, public utility as defined in 757.005, electricity service supplier as defined in OAR 860-038-0005, telecommunications utility as defined in ORS 759.005, telecommunications carrier as defined in 759.400, telecommunications provider as defined in OAR 860-032-0001, consumer-owned utility as defined in ORS 757.270, cable ~~operator~~ Operator as defined in 30.192, association, cooperative, or government entity and their agents, lessees, or acting trustees or receivers, appointed by court, engaged in the management, operation, ownership, or control of any facility within Oregon.

(9) "Owner" means a public utility, telecommunications utility, or consumer-owned utility that owns or controls poles, structures, ducts, conduits, right of way, manholes, handholes or other similar facilities.

(10~~6~~) "Pattern of non-compliance" means a course of behavior that results in frequent, material violations of the Commission Safety Rules.

(11~~7~~) "Reporting ~~operator~~Operator" means an ~~operator~~ Operator that:

(a) Serves 20 customers or more within Oregon; or

(b) Is an electricity service supplier as defined in OAR 860-038-0005 and serves more than one retail electricity customer.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 756.040, 757.035, 757.039, 757.649, 758.215, 759.005 & 759.045

860-024-0005
Maps and Records

(1) Each utility shall keep on file current maps and records of the entire plant showing size, location, character, and date of installation of major plant items.

(2) Upon request, each utility shall file with the Commission an adequate description or maps to define the territory served. Maps must include all recently identified High Fire Risk Zones. All maps and records which the Commission may require the utility to file shall be in a form satisfactory to the Commission Staff.

Statutory/Other Authority: ORS 183, 756 & 757
Statutes/Other Implemented: ORS 756.040 & 757.020

860-024-0007
Location of Underground Facilities

An ~~operator~~ Operator and its customers shall comply with requirements of OAR chapter 952 regarding the prevention of damage to underground facilities.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.542 - 757.562, 757.649 & 759.045

860-024-0010
Construction, Operation, and Maintenance of Electrical Supply and Communication Lines

Every ~~operator~~ Operator shall construct, operate, and maintain electrical supply and communication lines in compliance with the standards prescribed by the 2017 Edition of the National Electrical Safety Code approved April 26, 2016, by the American National Standards Institute.

[Publications: Publications referenced are available for review from the Commission.]

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0011
Inspections of Electric Supply and Communication Facilities

(1) An O~~o~~perator of electric supply facilities or an ~~operator~~ Operator of communication facilities must:

(a) Construct, operate, and maintain its facilities in compliance with the Commission Safety Rules; and

(b) Conduct detailed inspections of its overhead facilities to identify violations of the Commission Safety Rules.

(A) The maximum interval between each detailed inspection cycle~~s~~ is ten years, with a recommended inspection rate of ten percent of overhead facilities per year. During the fifth year of each~~the~~ detailed inspection cycle, the O~~o~~perator must:

(i) Report to the Commission that 50 percent or more of its total facilities have been inspected pursuant to this rule; or

(ii) Report to the Commission that less than 50 percent of its total facilities have been inspected pursuant to this rule and provide a plan for Commission approval to inspect the remaining percentage within the next five years. The Commission may modify the plan or impose conditions to ensure sufficient inspection for safety purposes.

(B) Detailed inspections include, but are not limited to, visual checks, pole test and treat programs (only required for pole Owners) or practical tests of all facilities, to the extent required to identify violations of Commission Safety Rules. Where facilities are exposed to extraordinary conditions (including High Fire Risk Zones) or when an ~~operator~~ Operator has demonstrated a pattern of non-compliance with Commission Safety Rules, the Commission may require a shorter interval between inspections.

(c) Conduct detailed facility inspections of its underground facilities on a ten-year maximum cycle, with a recommended inspection rate of 10 percent of underground facilities per year.

(d) Maintain adequate written records of policies, plans and schedules to show that inspections and corrections are being carried out in compliance with this rule and OAR 860-024-0012. Each ~~operator~~ Operator must make these records available to the Commission upon its request.

(2) Each ~~operator~~ Operator of electric supply facilities must:

(a) Designate an annual geographic area (including High Fire Risk Zones as identified by Operators of electric supply facilities) to be inspected ~~-~~pursuant to subsection (1)(b) of this rule within its service territory;

(b) Provide timely notice of the designation of the annual geographic area to all ~~owners~~ Owners and ~~occupants~~Occupants. The annual coverage areas for the entire program must be made available in advance and in sufficient detail to allow all ~~operators~~ Operators with facilities in that service territory to plan needed inspection and correction tasks. Unless the parties otherwise agree, O~~o~~perators must be notified of any changes to the established annual geographic area designation no later than 12 months before the start of the next year's inspection. For High Fire Risk Zones, Operators must be notified of any changes to the designation of a High Fire Risk Zone no later than 60 days before the start of the year's inspection; and

(c) Perform onsite routine safety patrols of overhead electric supply lines and accessible facilities for hazards to the public. The maximum interval between safety patrols is two years, with a recommended rate of 50 percent of lines and facilities per year.

(d) Inspect electric supply stations on a 45 day maximum schedule.

(3) Effective Dates:

(a) Subsection (2)(a) of this rule is effective January 1, 2007.~~;~~

(b) Subsection (1)(b) of this rule is effective January 1, 2008.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0012
Prioritization of Repairs by Operators of Electric Supply Facilities and Operators of Communication Facilities

(1) A violation of the Commission Safety Rules that poses an imminent danger to life or property must be repaired, disconnected, or isolated by the ~~operator~~ Operator immediately after discovery.

(2) Except as otherwise provided by this rule, the ~~operator~~ Operator must correct violations of Commission Safety Rules no later than two years after discovery.

(3) An ~~operator~~ Operator may elect to defer correction of violations of the Commission Safety Rules that pose little or no foreseeable risk of danger to life or property to correction during the next major work activity.

(a) In no event shall a deferral under this section extend for more than ten years after discovery.

(b) The ~~operator~~ Operator must develop a plan detailing how it will remedy each such violation.

(c) If more than one ~~operator~~ Operator is affected by the deferral, all affected operators must agree to the plan. If any affected operators do not agree to the plan, the correction of violation(s) may not be deferred.

(4) After December 31, 2027, the only allowable conditions for deferrals as set forth in subsection (3) are those that accommodate schedules for local jurisdiction permitting issues or planned road construction projects. Plans for correction for deferrals due to these conditions must be submitted to Commission Staff for review and tracking.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0015
Ground Return

Every ~~operator~~ Operator with either alternating or direct current power lines or equipment within Oregon may use a connection to ground only for protection purposes. A ground connection shall not be used for the purpose of providing a return conductor for power purposes.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035, 757.649 & 759.045

860-024-0016
Minimum Vegetation Clearance Requirements

(1) For purposes of this rule:

(a) “Cycle Buster” means vegetation that will not make it through the routine trim cycle without encroaching on the required minimum clearances and, therefore require pruning midterm before the routine cycle is completed.

(b~~a~~) “Readily climbable” means vegetation having both of the following characteristics:

(A) Low limbs, accessible from the ground and sufficiently close together so that the vegetation can be climbed by a child or average person without using a ladder or other special equipment; and

(B) A main stem or major branch that would support a child or average person either within arms’ reach of an uninsulated energized electric line or within such proximity to the electric line that the climber could be injured by direct or indirect contact with the line.

(c~~b~~) “Vegetation” means trees, shrubs, and any other woody plants.

(d~~c~~) “Volts” means nominal voltage levels, measured phase-to-phase.

(2) The requirements in this rule provide the minimum standards for conductor clearances from vegetation to provide safety for the public and utility workers, reasonable service continuity, and fire prevention. Each O~~o~~perator of electric supply facilities must have a vegetation management program and keep appropriate records to ensure that timely trimming is accomplished to keep the designated minimum clearances. These records must be made available to the Commission upon request.

(3) Each O~~o~~perator of electric supply facilities must regularly trim or remove vegetation to maintain clearances from electric supply conductors. Operators of electric supply facilities must develop and regularly update vegetation plans and documentation that confirms compliance

with the minimum clearances in subsection (5) below. Upon request from Commission Staff, Operators must provide that information to Commission Staff. If clearances are not being maintained, the Commission may require the Operator to implement an alternative vegetation management program and/or specific trim cycles..

(4) Each ~~operator~~ Operator of electric supply facilities must trim or remove readily climbable vegetation as specified in section (5) of this rule to minimize the likelihood of direct or indirect access to a high voltage conductor by a member of the public or any unauthorized person.

(5) Under reasonably anticipated operational conditions, as well as adverse weather and wind conditions, an ~~operator~~ Operator of electric supply facilities must maintain the following minimum clearances of vegetation from conductors:

(a) Ten feet for conductors energized above 200,000 volts.

(b) Seven and one-half feet for conductors energized at 50,001 through 200,000 volts.

(c) Five feet for conductors energized at 600 through 50,000 volts.

(A) Clearances may be reduced to three feet if the vegetation is not readily climbable.

(B) Intrusion of limited small branches and new tree growth into this minimum clearance area is acceptable provided the vegetation does not come closer than six inches to the conductor.

(6) For conductors energized below 600 volts, an ~~operator~~ Operator of electric supply facilities must trim vegetation to prevent it from causing strain or abrasion on electric conductors. Where trimming or removal of vegetation is not practical, the O~~o~~perator of electric supply facilities must install suitable material or devices to avoid insulation damage by abrasion.

(7) In determining the extent of trimming or vegetation removal required to maintain the clearances required in section (5) of this rule, the ~~operator~~ Operator of electric supply facilities must consider at minimum the following factors for each conductor:

(a) Voltage;

(b) Location;

(c) Configuration;

(d) Sag of conductors at elevated temperatures and under wind and ice loading; ~~and~~

(e) Growth habit, strength, and health of vegetation (including rates of tree mortality) growing adjacent to the conductor, with the combined displacement of the vegetation, supporting structures, and conductors under adverse weather or routine wind conditions.

(f) The amount of trimming or vegetation removal required to minimize Cycle Buster vegetation interference of energized conductors.

(8) Each Operator of communications facilities must ensure vegetation around communications lines do not pose a foreseeable danger to the pole and electric supply Operator's facilities.

Statutory/Other Authority: ORS 183, 756, 757 & 758
Statutes/Other Implemented: ORS 757.035 & 758.280 - 758.286

860-024-0017
Vegetation Pruning Standards

An ~~operator~~ Operator that is an electric utility as defined in ORS 758.505 must perform tree and vegetation work associated with line clearance in compliance with the American National Standard for Tree Care Operations, ANSI A300 (Part 1) 2008 Pruning, approved May 1, 2008, by the American National Standards Institute.

[Publications: Publications referenced are available from the Agency.]

Statutory/Other Authority: ORS Ch. 756, 757 & 758
Statutes/Other Implemented: ORS 757.035 & 758.280-758.286

860-024-0018
High Fire Risk Zone Safety Standards

(1) Operators of electric facilities must, in High Fire Risk Zones, de-energize out of service, abandoned and non-critical supply equipment as determined by the Operator during fire season.

(2) Utility supply conductors shall not be attached to live trees and should only be attached to utility owned poles and structures designed to meet the strength and loading requirements of the National Electrical Safety Code. This subsection does not apply to customer-supplied equipment at the point of delivery. Compliance with this subsection must be achieved prior to December 31, 20217.

(3) In addition to the requirements set forth in OAR 860-024-0011, Operators of electric facilities in High Fire Risk Zones must:

(a) conduct at a minimum, enhanced "detailed inspections," including, but not limited to, in person, onsite visual checks, or practical tests of all facilities, to the extent required to mitigate fire risk and identify violations of Commission Safety Rules.

(b) for transmission systems energized at or above 50,001 volts, perform and document, at a minimum, detailed inspections via onsite climbing, drone or high-powered spotting scope to identify structural and conductor defects, as well as violations of Commission Safety Rules.

(4) In addition to the requirements set forth in 860-024-0011, Public Utility Operators of electric facilities must conduct annual fire season "safety patrols" in High Fire Risk Zones. Public Utility Operators of electric facilities shall perform and document, in per-son, fire safety patrols of overhead electric supply lines and accessible facilities for potential fire risks, including but not limited to, off right of way hazard trees, right of way access for first responders, seasonal vegetation damage, vegetation Cycle Buster clearance conditions as defined in 860-024-0016(1)(a), potential equipment failures, and deteriorated supply or communication facilities.

(5) The requirements set forth in (3) and (4) above do not preclude the use of technology developments that may improve the ease of and quality of inspections. The use of technologies does not eliminate the need for in person fire safety patrols described above.

(6) Beginning on December 31, 2027, Public Utility Owners of electric supply facilities and Occupants shall participate in "Joint Inspections" of facilities in High Fire Risk Zones to mitigate fire risk as well as identify violations of Commission Safety Rules.

(7) If dictated by a consumer owned utility pole Owner, beginning December 31, 2027 Occupants of poles owned by consumer owned utilities in High Fire Risk Zones will implement detailed inspection cycle alignment to mitigate fire risk and identify violations of Commission Safety Rules.

(8) A violation of Commission Safety Rules in High Fire Risk Zones affecting energized conductors, structures or pole defects and a heightened risk of wildfire, as identified by the Operator of electric facility, shall be corrected no later than 180 days after discovery, regardless of pole Ownership.

860-024-0020
Gas Pipeline Safety

Every gas ~~operator~~ Operator must construct, operate, and maintain natural gas and other gas facilities in compliance with the standards prescribed by:

(1) 49 CFR, Part 191, and amendments through No. 25 — Transportation of Natural and Other Gas by Pipeline; Annual Reports and Incident Reports in effect on March 24, 2017.

(2) 49 CFR, Part 192, and amendments through No. 123 — Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards in effect on April 14, 2017.

(3) 49 CFR, Part 192, Interim Final Rule and incorporated by reference American Petroleum Institute (API) Recommended Practices 1171; in effect 1/18/2017.

(4) 49 CFR, Part 199, and amendments through No. 27 — Control of Drug and Alcohol Use in Natural Gas, Liquefied Natural Gas, and Hazardous Liquid Pipeline Operations in effect on March 24, 2017.

(5) 49 CFR, Part 40, and amendments through No. 29 – Procedure for Transportation Workplace Drug and Alcohol Testing Programs in effect on October 3, 2012.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183, 756, 757
Statutes/Other Implemented: ORS 757.039

860-024-0021
Liquefied Natural Gas Safety

Every gas ~~operator~~ Operator must construct, operate, and maintain liquefied natural gas facilities in compliance with the standards prescribed by:

(1) 49 CFR, Part 191, and amendments through No. 25 — Transportation of Natural and Other Gas by Pipeline; Annual Reports and Incident Reports in effect on March 24, 2017.

(2) 49 CFR, Part 193, and amendments through No. 25 — Liquefied Natural Gas Facilities; Minimum Safety Standards in effect on March 6, 2015.

(3) 49 CFR, Part 199, and amendments through No. 27 — Control of Drug and Alcohol Use in Natural Gas, Liquefied Natural Gas, and Hazardous Liquid Pipeline Operations in effect on March 24, 2017.

(4) 49 CFR, Part 40, and amendments through No. 29 – Procedure for Transportation Workplace Drug and Alcohol Testing Programs in effect on October 3, 2012.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183, 756, 757
Statutes/Other Implemented: ORS 757.039

860-024-0025
Steam Heat — Construction, Operation, and Maintenance of Steam and Hot Water Transmission and Distribution Systems

A steam heat public utility shall construct, operate, and maintain steam and hot water transmission and distribution systems in accordance with the American Society of Mechanical Engineers Code for Pressure Piping, Section B31.1, 1989 Edition, an American National Standard.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183 & 756
Statutes/Other Implemented: ORS 756.040

860-024-0050
Incident Reports

(1) As used in this rule:

(a) "Self-propagating fire" means a fire that is self-fueling and will not extinguish without intervention.

(~~a~~b) "Serious injury to person" means, in the case of an employee, an injury which results in hospitalization. In the case of a non-employee, "serious injury" means any contact with an energized high-voltage line, or any incident which results in hospitalization. Treatment in an emergency room is not hospitalization.

(~~b~~c) "Serious injury to property" means:

(A) Damage to operator and non-operator property exceeding $100,000; or

(B) In the case of a gas operator, damage to property exceeding $5,000; or

(C) In the case of an electricity service supplier (ESS) as defined in OAR 860-038-0005, damage to ESS and non-ESS property exceeding $100,000 or failure of ESS facilities that causes or contributes to a loss of energy to consumers; or

(D) Damage to property which causes a loss of service to over 500 customers (50 customers in the case of a gas operator) for over two hours (five hours for an electric operator serving less than 15,000 customers) except for electric service loss that is restricted to a single feeder line and results in an outage of less than four hours.

(2) Except as provided in section (6) of this rule, every reporting operator must give immediate notice by telephone, by facsimile, by electronic mail, or personally to the Commission, of incidents attended by loss of life or limb, or serious injury to person or property, occurring in Oregon upon the premises of or directly or indirectly arising from or connected with the maintenance or operation of a facility.

(3) As soon as practicable following knowledge of the occurrence, all investor-owned electric utilities must report by telephone, by facsimile, by electronic mail, or personally to the Commission fire-related incidents:

(a) that are the subject of significant public attention or media coverage involving the utility's facilities or is in the utility's right-of-way; or

(b) where the utility's facilities are associated with the following conditions:

(A) a self-propagating fire of material other than electrical and/or communication facilities; and

(B) the resulting fire traveled greater than one linear meter from the ignition point

(~~3~~**4**) Except as provided in section (~~5~~**6**) of this rule, every reporting operator must, in addition to the notice given in sections (2) **and (3)** of this rule for an incident described in sections (2) **and (3)**, report in writing to the Commission within 20 days ~~of the occurrence~~ **of knowledge of the occurrence using Form 221 (FM 221) available on the Commission's website**. In the case of injuries to employees, a copy of the incident report form that is submitted to Oregon OSHA, Department of Consumer and Business Services, for reporting incident injuries, will normally suffice for a written report. In the case of a gas operator, copies of incident or leak reports submitted under 49 CFR Part 191 will normally suffice.

(~~4~~**5**) An incident report filed by a public or telecommunications utility in accordance with ORS 654.715 cannot be used as evidence in any action for damages in any suit or action arising out of any matter mentioned in the report.

(~~5~~**6**) A Peoples Utility District (PUD) is exempt from this rule if the PUD agrees, by signing an agreement, to comply voluntarily with the filing requirements set forth in sections (2) and (4).

(~~6~~**7**) Gas operators have additional incident and condition reporting requirements set forth in OARs 860-024-0020 and 860-024-0021.

Statutory/Other Authority: ORS 183, 654, 756, 757 & 759
Statutes/Other Implemented: ORS 654.715, 756.040, 756.105, 757.035, 757.039, 757.649, 759.030, 759.040 & 759.045

Oregon
Kate Brown, Governor

Public Utility Commission
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September 29, 2021

AR 638 Draft Phase II Rules

Attached to this letter are Public Utility Commission of Oregon Staff's (Staff) Draft Phase II Rules, as described in the July 28, 2021 Docket Strategy Announcement.

Staff notes that the draft rules include modifications to Division 24 Safety Standards, as well as, Phase II additions to the Division 300 Wildfire Mitigation Plan Phase I rules currently in the formal rulemaking phase in Docket No. AR 648.

As a reminder, the next steps in the informal phase of this docket are as follows:

- 10/11/2021: Workshop on draft rules – meeting details TBA
    - The need for additional workshops or comment opportunities may be identified at the workshop, which may impact the remainder of the informal phase schedule
- 10/18/2021: Written comments due
- 11/11/2021: Staff memo proposing final draft rules
- 11/16/2021: Public Meeting to move to formal rulemaking

If you have questions on the process or content of this rulemaking, contact: Lori Koho, Administrator Safety, Reliability, & Security Division, 503-576-9789, lori.koho@puc.oregon.gov.

Division 24

860-024-0000
Applicability of Division 24

(1) Unless otherwise noted, the rules in this division apply to every operator, as defined in OAR 860-024-0001.

(2) Upon request or its own motion, the Commission may waive any of the division 24 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 756.040, 757.035, 757.039, 757.649, 759.030, 759.040 & 759.045

860-024-0001
Definitions for Safety Standards

For purposes of this Division, except when a different scope is explicitly stated:

(1) “Commission Safety Rules,” as used in this section, mean the National Electric Safety Code (NESC), as modified or supplemented by the rules in OAR chapter 860, division 024.

(2) “Facility” means any of the following lines or pipelines including associated plant, systems, supporting and containing structures, equipment, apparatus, or appurtenances:

(a) A gas pipeline subject to ORS 757.039;

(b) A power line or electric supply line subject to ORS 757.035; or

(c) A telegraph, telephone, signal, or communication line subject to ORS 757.035.

(3) “Government entity” means a city, a county, a municipality, the state, or other political subdivision within Oregon.

(4) “High Risk Fire Zones” are geographic areas identified by Operators of electric facilities in their risk-based wildfire plans.

(5) “Joint Inspection” means an inspection that includes both the Owner and Occupant(s) of any utility pole, structure, duct or conduit.

(6~~4~~) “Material violation” means a violation that:

(a) Is reasonably expected to endanger life or property; or

(b) Poses a significant safety risk to any operator’s employees or a potential risk to the general public.

(7) “Occupant means any licensee, Government Entity, or other entity that constructs, operates, or maintains attachments on poles, structures or within conduits.

(~~5~~8) “Operator” means every person as defined in ORS 756.010, public utility as defined in 757.005, electricity service supplier as defined in OAR 860-038-0005, telecommunications utility as defined in ORS 759.005, telecommunications carrier as defined in 759.400, telecommunications provider as defined in OAR 860-032-0001, consumer-owned utility as defined in ORS 757.270, cable operator as defined in 30.192, association, cooperative, or government entity and their agents, lessees, or acting trustees or receivers, appointed by court, engaged in the management, operation, ownership, or control of any facility within Oregon.

(9) “Owner” means a public utility, telecommunications utility, or consumer-owned utility that owns or controls poles, structures, ducts, conduits, right of way, manholes, handholes or other similar facilities.

(10~~6~~) “Pattern of non-compliance” means a course of behavior that results in frequent, material violations of the Commission Safety Rules.

(11~~7~~) “Reporting operator” means an operator that:

(a) Serves 20 customers or more within Oregon; or

(b) Is an electricity service supplier as defined in OAR 860-038-0005 and serves more than one retail electricity customer.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 756.040, 757.035, 757.039, 757.649, 758.215, 759.005 & 759.045

860-024-0005
Maps and Records

(1) Each utility shall keep on file current maps and records of the entire plant showing size, location, character, and date of installation of major plant items.

(2) Upon request, each utility shall file with the Commission an adequate description or maps to define the territory served. All maps and records which the Commission may require the utility to file shall be in a form satisfactory to the Commission.

(3) Operators of electric facilities in High Fire Risk Zones shall provide its most current High Fire Risk Zone maps by April 1st of each year in a form satisfactory to the Safety Staff.

Statutory/Other Authority: ORS 183, 756 & 757
Statutes/Other Implemented: ORS 756.040 & 757.020

860-024-0007
Location of Underground Facilities

An ~~operator~~ Operator and its customers shall comply with requirements of OAR chapter 952 regarding the prevention of damage to underground facilities.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.542 - 757.562, 757.649 & 759.045

860-024-0010
Construction, Operation, and Maintenance of Electrical Supply and Communication Lines

Every ~~operator~~ Operator shall construct, operate, and maintain electrical supply and communication lines in compliance with the standards prescribed by the 2017 Edition of the National Electrical Safety Code approved April 26, 2016, by the American National Standards Institute.

[Publications: Publications referenced are available for review from the Commission.]

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0011
Inspections of Electric Supply and Communication Facilities

(1) An O~~o~~perator of electric supply facilities or an operator of communication facilities must:

(a) Construct, operate, and maintain its facilities in compliance with the Commission Safety Rules; and

(b) Conduct detailed inspections of its overhead facilities to identify violations of the Commission Safety Rules.

(A) The maximum interval between each detailed inspection cycle~~s~~ is ten years, with a recommended inspection rate of ten percent of overhead facilities per year. During the fifth year of each~~the~~ detailed inspection cycle, the O~~o~~perator must:

(i) Report to the Commission that 50 percent or more of its total facilities have been inspected pursuant to this rule; or

(ii) Report to the Commission that less than 50 percent of its total facilities have been inspected pursuant to this rule and provide a plan for Commission approval to inspect the remaining percentage within the next five years. The Commission may modify the plan or impose conditions to ensure sufficient inspection for safety purposes.

(B) Detailed inspections include, but are not limited to, visual checks, pole test and treat programs or practical tests of all facilities, to the extent required to identify violations of Commission Safety Rules. Where facilities are exposed to extraordinary conditions (including High Fire Risk Zones) or when an operator has demonstrated a pattern of non-compliance with Commission Safety Rules, the Commission may require a shorter interval between inspections.

(c) Conduct detailed facility inspections of its underground facilities on a ten-year maximum cycle, with a recommended inspection rate of 10 percent of underground facilities per year.

(d) Maintain adequate written records of policies, plans and schedules to show that inspections and corrections are being carried out in compliance with this rule and OAR 860-024-0012. Each ~~operator~~ Operator must make these records available to the Commission upon its request.

(2) Each ~~operator~~ Operator of electric supply facilities must:

(a) Designate an annual geographic area to be inspected ~~-~~pursuant to subsection (1)(b) of this rule within its service territory. This includes High Fire Risk Zones as identified by Operators of electric supply facilities;

(b) Provide timely notice of the designation of the annual geographic area to all ~~owners~~ Owners and ~~occupants~~Occupants. The annual coverage areas for the entire program must be made available in advance and in sufficient detail to allow all operators with facilities in that service territory to plan needed inspection and correction tasks. Unless the parties otherwise agree, operators must be notified of any changes to the established annual geographic area designation no later than 12 months before the start of the next year's inspection; and

(c) Perform routine safety patrols of overhead electric supply lines and accessible facilities for hazards to the public. The maximum interval between safety patrols is two years, with a recommended rate of 50 percent of lines and facilities per year.

(d) Inspect electric supply stations on a 45 day maximum schedule.

(3) Effective Dates:

(a) Subsection (2)(a) of this rule is effective January 1, 2007.~~;~~

(b) Subsection (1)(b) of this rule is effective January 1, 2008.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0012
Prioritization of Repairs by Operators of Electric Supply Facilities and Operators of Communication Facilities

(1) A violation of the Commission Safety Rules that poses an imminent danger to life or property must be repaired, disconnected, or isolated by the operator immediately after discovery.

(2) Except as otherwise provided by this rule, the ~~operator~~ Operator must correct violations of Commission Safety Rules no later than two years after discovery.

(3) An ~~operator~~ Operator may elect to defer correction of violations of the Commission Safety Rules that pose little or no foreseeable risk of danger to life or property to correction during the next major work activity.

(a) In no event shall a deferral under this section extend for more than ten years after discovery.

(b) The ~~operator~~ Operator must develop a plan detailing how it will remedy each such violation.

(c) If more than one ~~operator~~ Operator is affected by the deferral, all affected operators must agree to the plan. If any affected operators do not agree to the plan, the correction of violation(s) may not be deferred.

(4) The exception in subsection (3) expires on 12/31/2027.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035

860-024-0015
Ground Return

Every ~~operator~~ Operator with either alternating or direct current power lines or equipment within Oregon may use a connection to ground only for protection purposes. A ground connection shall not be used for the purpose of providing a return conductor for power purposes.

Statutory/Other Authority: ORS 183, 756, 757 & 759
Statutes/Other Implemented: ORS 757.035, 757.649 & 759.045

860-024-0016
Minimum Vegetation Clearance Requirements

(1) For purposes of this rule:

(a) “Cycle Buster” means vegetation that will not make it through the routine trim cycle without encroaching on the required minimum clearances and, therefore require pruning midterm before the routine cycle is completed.

(b~~a~~) “Readily climbable” means vegetation having both of the following characteristics:

(A) Low limbs, accessible from the ground and sufficiently close together so that the vegetation can be climbed by a child or average person without using a ladder or other special equipment; and

(B) A main stem or major branch that would support a child or average person either within arms’ reach of an uninsulated energized electric line or within such proximity to the electric line that the climber could be injured by direct or indirect contact with the line.

(c~~b~~) “Vegetation” means trees, shrubs, and any other woody plants.

(d~~c~~) “Volts” means nominal voltage levels, measured phase-to-phase.

(2) The requirements in this rule provide the minimum standards for conductor clearances from vegetation to provide safety for the public and utility workers, reasonable service continuity, and fire prevention. Each O~~o~~perator of electric supply facilities must have a vegetation management program and keep appropriate records to ensure that timely trimming is accomplished to keep the designated minimum clearances. These records must be made available to the Commission upon request.

(3) Each O~~o~~perator of electric supply facilities must regularly trim or remove vegetation to maintain clearances from electric supply conductors. A minimum three-year trim cycle rate is required, unless the Operator of electric supply facilities submits documentation confirming compliance with the minimum clearances in (5) below utilizing alternate trim cycles and receives confirmation from Safety Staff that an alternate trim cycle is permissible.

(4) Each ~~operator~~ Operator of electric supply facilities must trim or remove readily climbable vegetation as specified in section (5) of this rule to minimize the likelihood of direct or indirect access to a high voltage conductor by a member of the public or any unauthorized person.

(5) Under reasonably anticipated operational conditions, including adverse weather and wind conditions, an ~~operator~~ Operator of electric supply facilities must maintain the following minimum clearances of vegetation from conductors:

(a) Ten feet for conductors energized above 200,000 volts.

(b) Seven and one-half feet for conductors energized at 50,001 through 200,000 volts.

(c) Five feet for conductors energized at 600 through 50,000 volts.

(A) Clearances may be reduced to three feet if the vegetation is not readily climbable.

(B) Intrusion of limited small branches and new tree growth into this minimum clearance area is acceptable provided the vegetation does not come closer than six inches to the conductor.

(6) For conductors energized below 600 volts, an ~~operator~~ Operator of electric supply facilities must trim vegetation to prevent it from causing strain or abrasion on electric conductors. Where trimming or removal of vegetation is not practical, the O~~o~~perator of electric supply facilities must install suitable material or devices to avoid insulation damage by abrasion.

(7) In determining the extent of trimming or vegetation removal required to maintain the clearances required in section (5) of this rule, the ~~operator~~ Operator of electric supply facilities must consider at minimum the following factors for each conductor:

(a) Voltage;

(b) Location;

(c) Configuration;

(d) Sag of conductors at elevated temperatures and under wind and ice loading; ~~and~~

(e) Growth habit, strength, and health of vegetation growing adjacent to the conductor, with the combined displacement of the vegetation, supporting structures, and conductors under adverse weather or routine wind conditions.

(f) The amount of trimming or vegetation removal required inside and outside the right-of-way, to minimize Cycle Buster vegetation interference of energized conductors.

(8) Each Operator of communications facilities must ensure vegetation around communications lines does not pose a foreseeable danger to the pole and electric supply Operator's facilities.

Statutory/Other Authority: ORS 183, 756, 757 & 758
Statutes/Other Implemented: ORS 757.035 & 758.280 - 758.286

860-024-0017
Vegetation Pruning Standards

An ~~operator~~ Operator that is an electric utility as defined in ORS 758.505 must perform tree and vegetation work associated with line clearance in compliance with the American National Standard for Tree Care Operations, ANSI A300 (Part 1) 2008 Pruning, approved May 1, 2008, by the American National Standards Institute.

[Publications: Publications referenced are available from the Agency.]

Statutory/Other Authority: ORS Ch. 756, 757 & 758
Statutes/Other Implemented: ORS 757.035 & 758.280-758.286

860-024-0018
High Fire Risk Zone Safety Standards

(1) Operators of electric facilities must, in High Fire Risk Zones, de-energize out of service, abandoned and non-critical supply equipment as determined by the Operator during fire season.

(2) Utility supply conductors shall not be attached to live trees and should only be attached to utility owned poles and structures designed to meet the strength and loading requirements of the National Electrical Safety Code. This subsection does not apply to customer-supplied equipment at the point of delivery. Compliance with this subsection is effective as of 12/31/2027.

(3) In addition to the requirements set forth in 860-024-0011, Operators of electric facilities in High Fire Risk Zones must:

(a) conduct at a minimum, enhanced detailed inspections, including, but are not limited to, in person, onsite visual checks, or practical tests of all facilities, to the extent required to mitigate fire risk and identify violations of Commission Safety Rules.

(b) for transmission systems energized at or above 50,001 volts, perform and document, at a minimum, detailed inspections via onsite climbing or high-powered spotting scope to identify structural and conductor defects, as well as violations of Commission Safety Rules.

(4) In addition to the requirements set forth in 860-024-0011, Public Utility Operators of electric facilities must conduct annual fire season safety patrols in High Fire Risk Zones. Public Utility Operators of electric facilities shall perform and document, in person, fire safety patrols of overhead electric supply lines and accessible facilities for potential fire risks, including but not limited to, off right of way hazard trees, right of way access for first responders, seasonal vegetation damage, vegetation Cycle Buster clearance conditions as defined in 860-024-0016(1)(a), potential equipment failures, and deteriorated supply or communication facilities.

(5) Public Utility Owners of electric supply facilities and pole Occupants in High Fire Risk Zones shall participate in “Joint Inspections” of facilities to identify violations of Commission Safety Rules and mitigate fire risk.

(6) Beginning on 12/31/2027, at the discretion of the pole owner, Consumer Owned Utility Pole Owners and Occupants in High Fire Risk Zones will implement detailed inspection cycle alignment to identify violations of Commission Safety Rules and mitigate fire risk.

(7) A violation of Commission Safety Rules in High Fire Risk Zones affecting energized conductors and a heightened risk of wildfire, as identified by the Operator of electric facility, shall be corrected no later than 180 days after discovery, regardless of pole ownership.

860-024-0020
Gas Pipeline Safety

Every gas ~~operator~~ Operator must construct, operate, and maintain natural gas and other gas facilities in compliance with the standards prescribed by:

(1) 49 CFR, Part 191, and amendments through No. 25 — Transportation of Natural and Other Gas by Pipeline; Annual Reports and Incident Reports in effect on March 24, 2017.

(2) 49 CFR, Part 192, and amendments through No. 123 — Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards in effect on April 14, 2017.

(3) 49 CFR, Part 192, Interim Final Rule and incorporated by reference American Petroleum Institute (API) Recommended Practices 1171; in effect 1/18/2017.

(4) 49 CFR, Part 199, and amendments through No. 27 — Control of Drug and Alcohol Use in Natural Gas, Liquefied Natural Gas, and Hazardous Liquid Pipeline Operations in effect on March 24, 2017.

(5) 49 CFR, Part 40, and amendments through No. 29 – Procedure for Transportation Workplace Drug and Alcohol Testing Programs in effect on October 3, 2012.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183, 756, 757
Statutes/Other Implemented: ORS 757.039

860-024-0021
Liquefied Natural Gas Safety

Every gas ~~operator~~ Operator must construct, operate, and maintain liquefied natural gas facilities in compliance with the standards prescribed by:

(1) 49 CFR, Part 191, and amendments through No. 25 — Transportation of Natural and Other Gas by Pipeline; Annual Reports and Incident Reports in effect on March 24, 2017.

(2) 49 CFR, Part 193, and amendments through No. 25 — Liquefied Natural Gas Facilities; Minimum Safety Standards in effect on March 6, 2015.

(3) 49 CFR, Part 199, and amendments through No. 27 — Control of Drug and Alcohol Use in Natural Gas, Liquefied Natural Gas, and Hazardous Liquid Pipeline Operations in effect on March 24, 2017.

(4) 49 CFR, Part 40, and amendments through No. 29 – Procedure for Transportation Workplace Drug and Alcohol Testing Programs in effect on October 3, 2012.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183, 756, 757
Statutes/Other Implemented: ORS 757.039

860-024-0025
Steam Heat — Construction, Operation, and Maintenance of Steam and Hot Water Transmission and Distribution Systems

A steam heat public utility shall construct, operate, and maintain steam and hot water transmission and distribution systems in accordance with the American Society of Mechanical Engineers Code for Pressure Piping, Section B31.1, 1989 Edition, an American National Standard.

[Publications: Publications referenced are available from the agency.]

Statutory/Other Authority: ORS 183 & 756
Statutes/Other Implemented: ORS 756.040

860-024-0050
Incident Reports

(1) As used in this rule:

(a) “Self-propagating fire” means a fire that is self-fueling and will not extinguish without intervention.

(~~a~~b) “Serious injury to person” means, in the case of an employee, an injury which results in hospitalization. In the case of a non-employee, “serious injury” means any contact with an energized high-voltage line, or any incident which results in hospitalization. Treatment in an emergency room is not hospitalization.

(~~b~~c) “Serious injury to property” means:

(A) Damage to operator and non-operator property exceeding $100,000; or

(B) In the case of a gas operator, damage to property exceeding $5,000; or

(C) In the case of an electricity service supplier (ESS) as defined in OAR 860-038-0005, damage to ESS and non-ESS property exceeding $100,000 or failure of ESS facilities that causes or contributes to a loss of energy to consumers; or

(D) Damage to property which causes a loss of service to over 500 customers (50 customers in the case of a gas operator) for over two hours (five hours for an electric operator serving less than 15,000 customers) except for electric service loss that is restricted to a single feeder line and results in an outage of less than four hours.

(2) Except as provided in section (6) of this rule, every reporting operator must give immediate notice by telephone, by facsimile, by electronic mail, or personally to the Commission, of incidents attended by loss of life or limb, or serious injury to person or property, occurring in Oregon upon the premises of or directly or indirectly arising from or connected with the maintenance or operation of a facility.

(3) As soon as practicable following knowledge of the occurrence, all investor-owned electric utilities must report by telephone, by facsimile, by electronic mail, or personally to the Commission fire-related incidents:

(a) that are the subject of significant public attention or media coverage involving the utility's facilities or is in the utility's right-of-way; or

(b) where the utility's facilities are associated with the following conditions:

(A) a self-propagating fire of material other than electrical and/or communication facilities; and

(B) the resulting fire traveled greater than one linear meter from the ignition point

(~~3~~**4**) Except as provided in section (~~5~~**6**) of this rule, every reporting operator must, in addition to the notice given in sections (2) **and (3)** of this rule for an incident described in sections (2) **and (3)**, report in writing to the Commission within 20 days ~~of the occurrence~~ **of knowledge of the occurrence using Form 221 (FM 221) available on the Commission's website**. In the case of injuries to employees, a copy of the incident report form that is submitted to Oregon OSHA, Department of Consumer and Business Services, for reporting incident injuries, will normally suffice for a written report. In the case of a gas operator, copies of incident or leak reports submitted under 49 CFR Part 191 will normally suffice.

(~~4~~**5**) An incident report filed by a public or telecommunications utility in accordance with ORS 654.715 cannot be used as evidence in any action for damages in any suit or action arising out of any matter mentioned in the report.

(~~5~~**6**) A Peoples Utility District (PUD) is exempt from this rule if the PUD agrees, by signing an agreement, to comply voluntarily with the filing requirements set forth in sections (2) and (4).

(~~6~~**7**) Gas operators have additional incident and condition reporting requirements set forth in OARs 860-024-0020 and 860-024-0021.

Statutory/Other Authority: ORS 183, 654, 756, 757 & 759
Statutes/Other Implemented: ORS 654.715, 756.040, 756.105, 757.035, 757.039, 757.649, 759.030, 759.040 & 759.045

Division 300

860-300-0001
Scope and Applicability of Rules

(1) The rules in this division prescribe the filing requirements for risk-based Wildfire Mitigation Plans filed by an electric utility as defined by ORS 757.600.

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0002
Definitions for this Division

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

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

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

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

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

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

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

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

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

(10) "Wildfire Mitigation Plan" is the same as a "wildfire protection plan" and refers to the document filed with the Commission relating to an electric utility's risk-based plan designed to

protect public safety, reduce the risk of utility facilities causing wildfires, reduce risk to utility customers, and promote electric system resilience to wildfire damage.

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0003
Public Utility Wildfire Mitigation Plan Filing Requirements
(*note: this will be an amendment to the anticipated adoption of rules in AR 648)

(1) Wildfire Mitigation Plans and Updates must, at a minimum, contain the following requirements as set forth in SB 762, Section 3(2)(a)-(h) and as supplemented below:

(a) Identified areas that are subject to a heightened risk of wildfire and identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.

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

(c) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure, including a PSPS communication strategy consistent with OAR 860-300-0005 through 860-300-0006.

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

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

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

(g) Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season, consistent with OAR 860-300-0005 and OAR 860-300-0006.

(h) Description of participation in national and international forums, including workshops identified in SB 967, Section 2, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used develop implement cost-effective wildfire mitigation solutions.

(2) A Public Utility's initial Wildfire Mitigation Plan must be filed no later than December 31, 2021. Wildfire Mitigation Plans must be updated annually and filed with the Commission.

(3) Within 180 days of submission, Wildfire Mitigation Plans and Wildfire Mitigation Plan Updates may be approved or approved with conditions through a process identified by the Commission in utility-specific proceedings, which may include retention of an Independent

Evaluator (IE). For purposes of this section, "approved" means the Commission finds that the Wildfire Mitigation Plan or Update is based on reasonable and prudent practices including those the Public Utility identified through Commission workshops identified in SB 762, Section 2, and designed to meet all applicable rules and standards adopted by the Commission.

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0004
Risk Analysis

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

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

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

(B) Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months. Examples include cumulative precipitation and fuel moisture content.

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

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

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

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

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

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

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

(A) Public Safety Power Shutoffs

(B) Vegetation Management,

(C) System Hardening,

(D) Investment decisions, and

(E) Operational decisions.

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0005
Wildfire Mitigation Plan Engagement Strategies

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

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

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

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

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

(2) The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Education and Awareness Strategy. The Education and Awareness Strategy must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities. The Education and Awareness Strategy will include, at a minimum:

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

(b) A description of the Public Utility's wildfire mitigation strategy.

(c) Training on emergency kits/plans/checklists.

(d) Public Utility contact and website information.

(e) Education and preparedness media platforms to inform the public.

(f) Frequency of preparedness and outreach to inform the public.

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

(A) Multiple languages prevalent to the area.

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

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

(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the Public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specified in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0006. The Coordination Strategy should include, at a minimum:

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

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0006
Communications Requirements Prior, During, and After a Public Safety Power Shutoff

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

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

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

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

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

(D) Number of customers impacted by PSPS;

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

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

(G) Notice of when re-energization begins and when re-energization is complete;

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

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

(A) Date and time PSPS will be executed;

(B) Estimated duration of PSPS;

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

(D) Notice of when re-energization begins and when re-energization is complete.

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

(2) When a Public Utility determines that a PSPS is likely to occur, the Public Utility must provide advance notice of the PSPS to customers via a PSPS web-based interface on the Public Utility's website and other media platforms, and may communicate PSPS information directly with customers consistent with 860-300-0006(b).

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

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

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

(C) Display on its website homepage a prominent link to access current information about the PSPS, consistent with OAR 860-300-0007, including a depiction of the boundary. The PSPS information must be easily readable and accessible from mobile devices.

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

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

(B) Date and time PSPS will be executed;

(C) Estimated duration of PSPS;

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

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

(F) After initial notification, the Public Utility will provide, at a minimum, status updates at 24-hour intervals until service has been restored;

(G) Notice of when re-energization begins and when re-energization is complete.

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

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

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

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

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0007
Ongoing Informational Requirements for Public Safety Power Shutoffs

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

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

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

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

(5) The Public Utility will provide a comprehensive narrative of each subsection of this rule as part of its annual Wildfire Mitigation Plan.

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0008
Reporting Requirements for Public Safety Power Shutoffs

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

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

Statutory/Other Authority:
Statutes/Other Implemented:

860-300-0009
Cost Recovery

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

Statutory/Other Authority:
Statutes/Other Implemented:

OAR 860-300-0010
Consumer-owned Utility Plans

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

Statutory/Other Authority:
Statutes/Other Implemented:

Attachment C: Stakeholder comments on OAR 860-0024-0018(6) with Staff's response.

Staff's proposed OAR 860-024-0018(6): "Beginning on December 31, 2027, Public Utility Owners of electric supply facilities Occupant shall participate in "Joint Inspections" of facilities in High Fire Risk Zones to mitigate fire risk as well as identify violations of Commission Safety Rules."

Summary of Stakeholder Comments:

Stakeholder Comment	Staff's Response
Multiple COUs objected to joint inspections	The rule is voluntary for COUs
CTI objects to joint inspections, they claim that their experience with joint inspections resulted with the inspector hired by the electric utility not understanding or focusing on telecommunication facilities and the telco had to go to the pole and verify the inspection.	This can be resolved working together with training.
CTI states there is already a shortage of inspectors	The rule does not specify how this process will be implemented. A well operated program should reduce the number of inspectors needed. Many utility poles have multiple attachees. At this point, each has to visit the pole. A joint inspection with a single contractor approved to perform inspections of power and telecommunications eliminates the need for multiple inspectors.
Communication providers have already established 10 year inspection cycles and this change would mean they might be out of compliance with existing rules	Staff has assured it will support a reasonable rule waiver request for anyone participating in a joint inspection program. Joint inspection promotes safety and ensures the pole owner and attachers understand how and what each party is responsible for to bring a utility pole into compliance.
PGE opines it has more than 100 different occupants on poles throughout its service territory. It also asserts this issue should be explored in a separate docket so all parties impacted have the opportunity to participate in the discussion.	Staff disagrees with PGE's request. Identifying and correcting violations consistently and in a timely fashion is one of the keys to safety. Currently, correcting violations can be influenced by one attacher claiming it is another attachers fault for a violation. Or correction of one violation is dependent on someone else first correcting its violation. And sometimes the notification tools are ineffective so when an attacher is notified, it needs to allow another attacher to correct its facilities, resulting in a lost notification. Staff has observed this when reviewing records. Utilities have complained about these weaknesses in the notification systems in various industry meetings Staff

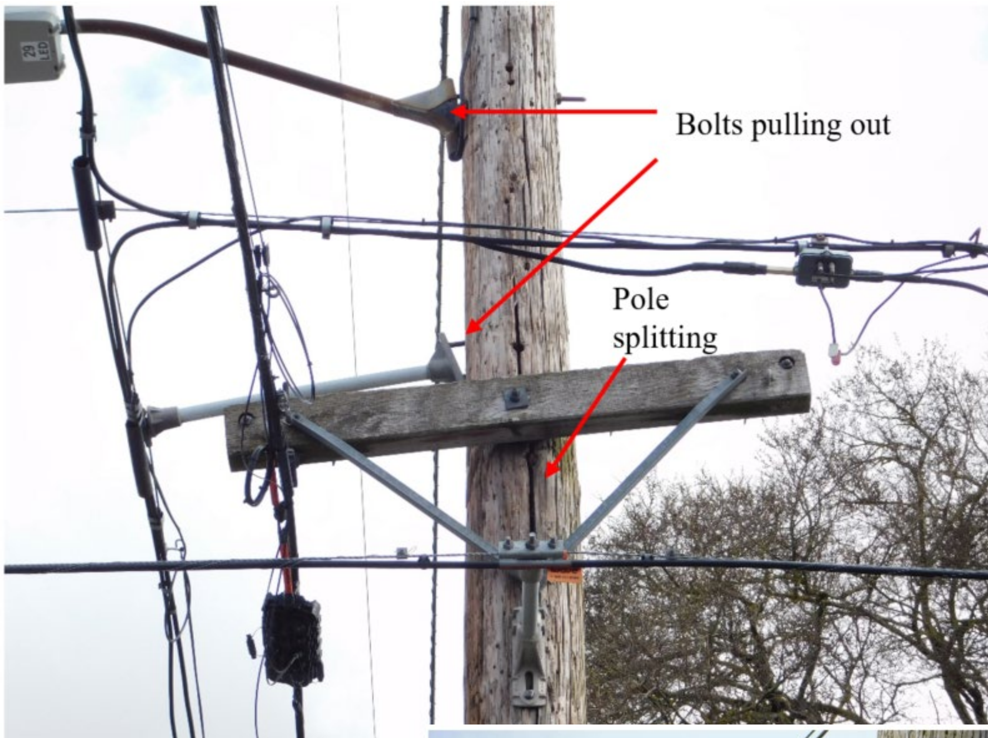
	has attended. This problem has been simmering since the inception of the current rules. The Commission was assured that collaboration between attachers would put any concerns to rest. This is not Staff's observation. This is not an issue of the relationship in joint use. This is a fundamental safety issue that is being ignored. None of the pole owners have filed a formal complaint with the Commission to resolve unsafe conditions on their poles. This is the justification behind Staff's proposed rule. At a single point in time, all attachers agree to the results of the inspection and will agree on a plan to correct within the specified time. If an attacher refuses to respond or participate, the pole owner or IOU can file a formal complaint with the Commission. Again, this a fundamental safety issue that is outside of renegotiating contracts. When the electric utility or pole owner knows there are facilities adjacent to it that are not in compliance with Commission rules, it can be viewed as liable for any consequence resulting from it.
Idaho Power asserts that requirements for joint inspection are beyond the scope of this rulemaking.	See Staff's previous response.
OCTA comments that the Commission previously rejected proposals to mandate joint inspections.	Staff understands the Commission's reasoning at the time of Order No. 06-547. Staff also asserts that 1) Staff has 15 years of data illustrating poor compliance with the rules by telecommunications providers. 2) Investigations of fires in California have identified wildfires associated with maintenance of telecommunications facilities. If we were only addressing the general lack of compliance with rules and conditions called for in joint use, Staff would agree all of this should be covered in a separate docket. In fact, the joint use rules should be revisited. However, we are now aware of wildfires being sparked by telecommunication facilities that were poorly maintained. Times have changed. Wildfire mitigation requires immediate action independent of the joint use rules.

OCTA opines when their members have participated in joint inspections it has been difficult to coordinate.	Staff has directly heard reports of results of pilot and permanently implemented joint inspection programs that have been successful in increasing compliance with rules and reducing costs.

Attachment D: Examples of Safety violations found by Staff that had not been corrected.

This pole was labeled as in emergency reject in 2018. Based on a consumer complaint, Staff went to the location to inspect the pole. They took photos and contact the pole Owner and Occupant. The utility responded that day and replaced the pole. The utility pole is owned by the telecommunications utility.

Telecommunications utility owned pole. Identified by the electric operator and Staff later found during an inspection that it had not been corrected.



Staff discovered this pole and many others not pictured here during its April 14, 2021 inspections in the Hillsboro area.
According to utility records, the poles had been identified as Bad Order Poles in 2018

Customer originally complained about this pole in 2016. The customer complained again in 2020.
Tags are from two separate inspections. Two yellow tags indicates need for emergency replacement. Two white tags means another inspector identified need for emergency replacement. The two red down around mean the pole is too dangerous to climb.
The electric utility had transferred its facilities off the pole but the communication facilities remain attached for some period.
When Staff went to the location on 3/10/2021, the telecommunication facilities had been transferred and the bad pole removed.

Found during Staff Inspection. Energized primary conductor attached to a tree. Does not meet requirement that facilities be attached to NESC compliant facility.

Found during Staff inspection. Example of broken lashing wires for telecommunication facilities.