PACIFIC POWER
A DIVISION OF PACIFICORP

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VIA ELECTRONIC FILING

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

RE: AR 638—PacifiCorp's Comments on Staff's Proposed Draft Permanent Rules

PacifiCorp d/b/a Pacific Power (PacifiCorp) respectfully submits these comments regarding the proposed amendments to Division 24 rules and the proposed new Division 300 rules. Attached is a redline version of each set of rules; please note that PacifiCorp' proposed revisions to Division 24 are shown in redline format, meaning that the Public Utility Commission of Oregon (Commission) Staff's redlines of the existing rules were "accepted" to make a clean version prior to making additional edits to reflect PacifiCorp's proposed changes.

1. <u>Integrating Another Tier of Priority Would Improve the Proposed Acceleration of the Timeframe for Corrections</u>.

PacifiCorp understands and supports Staff's underlying objective to accelerate the timeframe for corrections that pose a heightened wildfire risk in the High Fire Risk Zones. In Section 7 of new OAR 860-024-0018, Staff proposes that all identified violations "shall be corrected no later than 180 days after discovery."[1] PacifiCorp suggests that this amendment can be made more effective by integrating a tiered approach that recognizes the practical impact of the seasonal nature of the wildfire risk. PacifiCorp proposes that more significant conditions be corrected even faster than proposed by Staff—namely, within 90 days—with then a longer period of time for correction of less significant conditions, allowing a 12-month period for correction of those types of conditions.

The logic for this proposal is heavily influenced by the progression of seasons and the typical inspection schedule. Electric utilities operating in areas of elevated wildfire risk try to schedule inspections so that facilities in areas of elevated wildfire risk are inspected in the spring. Electric utilities want to conduct inspections after winter, so that any damage caused by winter weather is caught by the inspection (and because winter weather may limit physical access to some facilities), but also complete inspections before summer, so that priority corrections can be made before the worst parts of the wildfire season. Consequently, in areas of elevated wildfire risk, there is a strong push to complete a high percentage of inspections in the March–June timeframe. For conditions identified in this timeframe, however, a 180-day deadline for corrections would then fall in the September–December timeframe, which is not optimal for

[1] Obviously, the command in 860-024-0012 to immediately remedy "imminent dangers" remains unchanged by the proposed additions in new 860-024-0018.

mitigating wildfire risk. To mitigate wildfire risk more aggressively, electric utilities must make priority corrections much quicker. In practice, utilities are often striving to have priority corrections completed as soon as possible, to best mitigate the wildfire risk in July, August, and September. Against this background, a regulatory requirement for priority corrections within 90 days would better promote the goal of having corrections of the most significant conditions completed before the hottest and driest months.

To help manage resources and keep focus on higher priority issues, correction of conditions which have a lower fire risk is appropriately placed on a more extended timeframe. Conditions which correlate to a moderate risk of fire ignition should be corrected within 12 months of discovery. Because conditions identified in the spring would be corrected at least as early as the following spring, the wildfire mitigation impact would be roughly equivalent to an approach where such corrections take place close to a 180-day correction deadline. Under either scenario, the condition would persist only through one fire season cycle. Additionally, having six extra months to address lower priority conditions will allow utilities to focus efforts on the higher priority items. Other conditions, which do not correlate to either a moderate or significant fire risk, should be corrected consistent with OAR 860-024-0012. To facilitate this tiered approach, a utility will need to categorize the types of conditions which correlate to a risk of fire ignition. By applying an engineering review, categories of conditions can be classified as correlating to fire risk or not. This approach allows for a focus on correcting the conditions which correlate with the risk of fire ignition.

2. <u>More Aggressive Inspection Frequencies Will Enhance Wildfire Mitigation Efforts and Add Greater Objectivity to the New Rules Applicable to the High Fire Risk Zones</u>.

PacifiCorp proposes to integrate, in Section 3 of new OAR 860-024-0018, a firm requirement applicable to facilities in the High Fire Risk Zones for (a) detailed inspections every five years (rather than every 10 years) and (b) a safety patrol every year (rather than every two years). PacifiCorp appreciates Staff's efforts to build some discretion into the inspection provisions of proposed new OAR 860-024-0018(3)-(4), but the growing wildfire risk warrants a uniform increase of inspection frequency in the areas of greatest wildfire risk. The proposed approach would essentially double the number of inspections in the High Fire Risk Zones. (Recognizing that a 10-year cycle for pole test and treat is already relatively aggressive, PacifiCorp proposes that the requirement for a pole test and treat every 10 years also apply in the High Fire Risk Zone). PacifiCorp proposes removing softer language from new OAR 860-024-0018, to avoid any confusion on how the new section interacts with OAR 860-024-0011 and how the two types of inspections are defined. If any inspection method or technique not included in a normal OAR 860-024-0011 inspection is required, such method or technique should be expressly identified.

3. To Make Joint Inspections Correlate to More Timely Corrections, the Process for Completing Joint Inspections and Resulting Corrections Should be Mandated by Rule.

There are opportunities for using a joint inspection approach to improve efficiencies and, mostly importantly, accelerate corrections. But experience has shown that a stronger Commission role as "referee" is necessary to realize these objectives. The old saying of "too many cooks in the kitchen" applies to the world of joint inspections and joint corrections. Any party naturally wants to retain discretion over elements of its business, whether it be to select a contractor (and negotiate rates) or to decide when and how to perform work. But when multiple parties must reach agreement related to multiple action items—or otherwise exchange information and then wait for responses—any such process naturally takes more time as compared to when a single party manages the process.

If a joint inspection requirement is to be integrated into the rules, certain component parts should also be mandated by rule. In summary, the pole owner should schedule a joint inspection by an independent contractor, and a different independent contractor should be tasked with correcting the violations identified through the inspection. PacifiCorp has made proposed edits to OAR 860-024-0018 to effectuate this basic framework. To equitably split the cost of a joint inspection, PacifiCorp proposes a simple 50/50 split with Occupants. The greatest cost associated with an inspection is associated with the inspector physically travelling to the pole, so a 50/50 split is warranted. To the extent that the electric utility portion of a joint inspection requires more time or expertise, it should be noted that electric utilities are much more often the pole owner and will, consequently, bear a greater portion of the administrative costs. On the correction side, it is only fair that the party owning the equipment subject to repair or replacement be the party to pay for the correction (and be billed directly by the contractor performing the work). Occupants might complain about the selection of contractors being controlled by the pole owner (and, specifically, the pricing used by those contractors), but minimal Commission oversight on this issue could ensure, to Occupants' satisfaction, that contractors were selected in good faith, are qualified to make all types of corrections, and are charging prices at normal market rates.

4. Retaining an Exception to the Standard Correction Deadline Remains Justified, and Overuse Can Be Addressed by Narrowing the Exception.

There are some violations that impose so small of safety risk that deferring correction until other work is performed on the pole is justified in the interest of economic efficiency. In general, any irregularity on the pole is treated as a "violation." Nonetheless, certain of these conditions are so minor that dispatching a crew to the location just to fix a single minor condition poses an unnecessary cost. Additionally, the risk posed to the crew to correct such minor conditions is often greater than the risk posed by the condition itself. Historically, recognizing these efficiency concerns, OAR 860-024-0012(3) has provided an exception for these types of violations to the standard correction timeframe requirement of two years. PacifiCorp understands that some stakeholders have concerns that this exception has been over applied, and

PacifiCorp understands why, in the face of today's elevated wildfire risk, Staff wants to respond to those concerns, proposing to phase out the exception by 2027.

While recognizing these concerns, the logic behind the exception still makes sense. For example, dispatching a crew to install a small sign that almost certainly will never be seen by any person incurs an unnecessary cost, borne by consumers, and an unnecessary risk, borne by the crew. Rather than completely phase out the exception by 2027, PacifiCorp proposes to narrow the scope of the exception. A workable solution has been tried and tested in California, where a discrete list of condition types have been identified for this purpose. (See California General Order 95 Appendix J). PacifiCorp proposes to narrow the exception by expressly integrating this list of applicable conditions into the text of OAR 860-024-0012.

5. <u>Shortening the Mandated Trim Cycle and Requiring Annual Vegetation Inspections are Notable Enhancements to the PacifiCorp' Vegetation Management Programs</u>.

PacifiCorp generally supports the substantive enhancements to the vegetation management provisions of Division 24 and suggest minor edits for clarification. The most substantial addition is in Section 4 of the proposed new section OAR 860-024-0018, which contemplates an annual inspection in the High Fire Risk Zones. PacifiCorp recognizes the heightened risk associated with vegetation contacts and agrees that an annual vegetation inspection is warranted. The edits proposed by PacifiCorp to Section 4 are intended to clarify that the new annual inspection requirement should capture all critical elements of the utility's vegetation management program. Specifically, the annual vegetation inspection should identify any hazard tree and clearance issues. Moreover, the vegetation inspection should be conducted by a person qualified to conduct vegetation inspections. While it remains feasible for the same individual person to perform a safety patrol and a vegetation inspection, experience suggests that two inspections will likely be necessary because of the different skill sets involved.

PacifiCorp also supports the uniform adoption of a three-year trim cycle. While other cycles can be equally effective, especially recognizing multiple variables in how any particular cycle might be employed (such as clearances achieved at the time of work and use of interim work), PacifiCorp appreciates the respective advantages in having a uniform cycle.

6. <u>The New Rules in Proposed Division 300</u>

PacifiCorp appreciates Staff's efforts to bring order to the administrative process around the new requirement for a wildfire mitigation plan and related issues, such as the use of public safety power shutoff. PacifiCorp proposes only minor edits to the new Division 300 rules, geared mostly to a few timing issues or to add clarity.

PacifiCorp appreciates the opportunity to provide these comments and recognizes Staff's leadership in facilitating the rulemaking process. PacifiCorp looks forward to continued participation in this proceeding.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulations

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~~of all equipment on any utility pole, structure, duct or conduit~~.~~ owned by either the Owner or an Occupant(s).

(6) “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.

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

(11) “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 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 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 Operator 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 is ten years, with a recommended inspection rate of ten percent of overhead facilities per year. During the fifth year of each detailed inspection cycle, the Operator 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 must make these records available to the Commission upon its request.

(2) Each 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 and 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 must correct violations of Commission Safety Rules no later than two years after discovery.

(3) An 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 must develop a plan detailing how it will remedy each such violation.

(c) If more than one 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.~~may only be applied with respect to the following types of violations or violations approved by the Commission:

(a) Missing or illegible high voltage signs or communication carrier identification tags in remote areas

(b) Damaged or missing guy markers in remote locations or not exposed to pedestrian traffic or vehicle traffic

(c) Reduced (minor) wire-to-wire clearances of insulated and energized service drops (0-750 volts) from the pole, at midspan, or at the customer service location

(d) Reduced down guy clearance from communication line

(e) Anchor guy with minimal slack where a pole is straight or leaning towards the anchor

(f) Idle or abandoned cable and service drops with no public exposure

(g) Climbing space obstructions from vegetation with incidental intrusion into the supply space that: (i) does not prevent work from being done and (ii) does not violate 860-024-0017 or 860-024-0016.

(h) Damaged / loose / idle hardware that: (i) is not in the climbing space and (ii) does not pose any risk to employees working on the pole or the public

(i) Missing or damaged bolt covers where only exposure is to qualified electric workers

(j) Damaged, missing or separated moulding (exposed ground) in remote areas or where only exposure is to qualified electric workers

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

860-024-0015
Ground Return

Every 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) “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) "Vegetation" means trees, shrubs, and any other woody plants.

(d) "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 Operator 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 Operator 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 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 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 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 Operator 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 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;

(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 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~~.~~ that pose elevated fire risk.

(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~~ every five (5) years; provided, however, that a pole test and treat is required every ten (10) years.

(b) conduct, at a minimum, an annual safety patrol on all facilities~~, to the extent required to mitigate fire risk and identify violations of Commission Safety Rules.~~ in all High Fire Risk Zones; and

(~~b~~c) 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~~0016, Public Utility Operators of electric facilities must conduct an annual ~~fire season safety patrols~~ vegetation inspection on all rights of way with overhead facilities in High Fire Risk Zones. ~~Public Utility Operators of electric facilities~~ The annual vegetation inspection shall ~~perform and document, in person, fire safety patrols of overhead electric supply lines and accessible facilities~~include an inspection for ~~potential fire risks, including but not limited to, off right of way~~ any hazard ~~trees, right~~tree (whether in or out of ~~way access for first responders, seasonal~~any defined easement area) and any vegetation ~~damage, vegetation Cycle Buster~~ clearance conditions as defined in 860-024-0016(1)(a), ~~potential equipment failures, and deteriorated supply or communication facilities.~~including any vegetation likely to become a clearance conditions prior to the next annual vegetation inspection.

(5) Public Utility Owners of electric supply facilities ~~and pole Occupants in High Fire Risk Zones~~ shall ~~participate in~~conduct “Joint Inspections” of facilities in High Fire Risk Zones to identify violations of Commission Safety Rules ~~and mitigate fire risk.~~. An Occupant shall pay for fifty percent (50%) of the inspection cost. (If there is more than one Occupant on a pole, each Occupant shall pay an equal part of the Occupant portion of the inspection cost.) The Public Utility Owner that conducted the Joint Inspection shall provide to an Occupant the inspection results of any violations involving any facilities owned by the Occupant.

(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~~Any violation of Commission Safety Rules in High Fire Risk Zones ~~affecting energized conductors and~~ which poses a ~~heightened~~ risk of ~~wildfire,~~ fire ignition shall be corrected as ~~identified by the Operator~~follows:

(a) any violation which correlates to a significant risk of ~~electric facility,~~fire ignition shall be corrected no later than ~~180~~90 days after discovery~~, regardless~~.

(b) any violations which correlates to a moderate risk of ~~pole ownership~~fire ignition shall be corrected no later than 12 months after discovery.

(c) all other violations requiring correction under Section 2 of 860-024-0012 shall be corrected consistent with OAR 860-024-0012.

(8) To complete correction under Section 2 of 860-024-0012 of any violation in High Fire Risk Zones, the Owner shall retain a qualified independent contractor and instruct the contractor to remedy all violations identified through a Joint Inspection. The contract for doing corrections shall require the independent contractor to use similar rates for all corrections. The contract for doing corrections shall provide that the independent contractor will bill (i) an Owner for all corrections of any violations involving any facilities owned by the Owner and (ii) an Occupant for all corrections any violations involving any facilities owned by the Occupant.

860-024-0020
Gas Pipeline Safety

Every gas 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 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, or monthly 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, one or more ~~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 was ~~must be~~ filed in~~no later than December 31, 2021~~2021. Wildfire Mitigation Plans must be updated annually and filed with the Commission, with the first update to be filed no later than December 31, 2022.

(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 be dynamic throughout the fire season~~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 potentially impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum:

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

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

(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) Education~~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) Anticipated ~~D~~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 restorations begins ~~until service has been restored~~ for PSPS events lasting longer than 24 hours;

(G) Notice of when restoration~~e-energization~~ begins and when restoration~~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) Anticipated ~~D~~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 restoration~~e-energization~~ begins and when restoration~~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: