Bear Valley Electric Service

Wildfire Mitigation Plan

2022 Revision 1

Bear Valley
Electric Service, Inc.
A Subsidiary of American States Water Company

August 29, 2022

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EXECUTIVE SUMMARY

The Bear Valley Electric Service, Inc. (BVES)[1] Wildfire Mitigation Plan (WMP or Plan) aims to reduce the risk of utility-caused ignitions or threats as well as to mitigate the need for public safety power shutoff (PSPS) events in the future. This WMP represents BVES's plan to continue to reduce utility wildfire risks, maintain reliability, meet its regulatory obligations for 2022, and plan for continuous improvement through future years within the WMP compliance cycle.[2]

During 2021, BVES did not experience any ignition events or need to activate PSPS to mitigate wildfire threats. BVES maintains its service territory with a foundational understanding of natural resource management in an area surrounded by mountainous terrain and forested slopes. To sustain its record of success, BVES works collaboratively with public safety partners, and state and federal agencies in an effort to ensure its region is well-prepared to face the ever-evolving threat of catastrophic wildfires. Despite an absence of utility caused ignitions or PSPS events, BVES embraces wildfire safety as a core competency in executed work, adopting fire operational standards, and continuously monitoring system and environmental conditions.

This WMP demonstrates the continued effort and investment underway at BVES and progress realized to reduce the probability of utility-caused ignitions and reduce the potential of wildfires to impact the reliable operation of the BVES system. The 2022 WMP Update[3] includes more data and objective content than its previous submissions and incorporates longer-term systematic thinking on reducing wildfire risks additively and cumulatively to improve BVES's wildfire mitigation maturity over time.

BVES seeks to direct its resources to the most cost-effective projects to bring down the risk while maintaining affordability and reliability. Specifically, BVES aims to 1) improve its understanding of the wildfire risk posed by and to its systems, 2) focus on reducing the highest risks aggressively and efficiently, and 3) maximize scarce financial and human resources in its efforts to mitigate wildfire risks.

On December 15, 2021, The Office of Energy Infrastructure Safety (OEIS or Energy Safety)[4] issued the 2022 WMP Guidelines.[5] The template is reflected in this 2022 WMP Update. The Plan represents a comprehensive, technically feasible, effective, efficient, and forward-looking plan to address the critical goal of reducing wildfire risk to BVES, its customers, and the community.

On July 22, 2022, Energy Safety issued its "Revision Notice for Bear Valley Electric Service, Inc.'s 2022 Wildfire Mitigation Plan Update." This revised WMP has addressed the revision requests from Energy Safety in the sections identified in the table below.

[1] BVES is a subsidiary of American States Water Company.

[2] Ongoing compliance for the WMP is directed from Resolution Wildfire Safety Division (WSD)-012, issued on November 23, 2021. The compliance reports include scheduled quarterly data reports (QDRs), quarterly initiative updates (QIUs), quarterly advice letters/notification letters (QALs), and the annual report on compliance (ARC).

[3] Concurrently submitted with this filing is the fourth quarter 2021 QDR and a spatial data layer package.

[4] In July 2021, the WSD fully transitioned to the Office of Energy Infrastructure Safety (OEIS or Energy Safety) under the California Natural Resources Agency (CNRA) as a separate entity governing regulated investor-owned utility (IOU) WMPs and associated compliance filings.

[5] Guidelines included Attachment 1: Summary of Changes for the 2022 WMP Update Guidelines, Attachment 2: 2022 WMP Update Guidelines, Attachment 3: Tables 1-12 Non-Spatial Metrics Data, Attachment 4: 2022 Maturity Model, and Attachment 5: Guidelines for Submission and Review of 2022 WMP Updates. The Guidelines were formally adopted on December 14, 2021 pursuant to Government Code 15475.6 and issued on December 15, 2021.

Summary of Actions in Response to Energy Safety's Revision Notice

Issue ID	Issue	Applicable WMP Sections
RN-BVES-22-01	BVES has not responded to "Additional Issues"	4.6, Appendix A
RN-BVES-22-02	BVES has not provided adequate detail on mitigation initiative progress	7.1, 7.3
RN-BVES-22-03	BVES has not sufficiently connected its risk assessment with its mitigation initiative prioritization	7.1, 7.3.3
RN-BVES-22-04	BVES has not provided sufficient information on quality assurance & quality control (QA/QC)	7.3.4, 7.3.5
RN-BVES-22-05	BVES claims aspects of its vegetation management program are "enhanced" despite meeting only minimum regulatory requirements	7.3.5
RN-BVES-22-06	BVES has misinterpreted data management initiatives	7.3.7
RN-BVES-22-07	BVES does not describe how quantifiable risk reductions and RSE estimates inform initiative selection	7.1
RN-BVES-22-08	BVES uses vague language to describe its service restoration workforce	5.4
RN-BVES-22-09	BVES uses vague language to describe United States Forest Service and fuel reduction cooperation activities	7.3.5
RN-BVES-22-10	BVES does not describe how its PSPS planning has evolved	7.3.6, 8.3
RN-BVES-22-4.1.B	Section 8386(c)(5) of the Public Utilities Code requires "a discussion of how the application of previously identified metrics to previous plan performances has informed the plan." This requirement was addressed in Section 4.1 of BVES's 2021 WMP Update but could be more complete.	Table 4.1-1
RN-BVES-22-4.4.A[6]	BVES fails to "Provide a summarized report detailing the overall percentage of FTEs with qualifications listed in (2) for each of the target roles."59 These qualifications include: "Going beyond a basic knowledge of General Order 95 requirements… Being a 'Qualified Electrical Worker' (QEW)… [and] being an International Society of Arboriculture (ISA) Certified Arborist with specialty certification as a Utility Specialist."	5.4
RN-BVES-22-5.2.A	BVES continues to discuss the installation of fiber optic communications in its service territory as a foundational investment to enable advanced technologies such as, wire down detection, rapid earth fault current limiter, and diagnostic technologies. However, BVES does not adequately address the conditions outlined by BVES-R5 (Class C). It remains unclear whether BVES is implementing a Down Wire Detection program or is still monitoring commercial development of Down Wire Detection technology.	7.3.3
RN-BVES-22- 5.3.A.1	BVES does not currently have a plan to directly address capacitor maintenance, instead relying on current	7.3.3

[6] This issue is considered closed according to an email from Colin Lang of Energy Safety on August 9, 2022.

Issue ID	Issue	Applicable WMP Sections
	maintenance practices. BVES states that it plans to evaluate capacitors in 2022 as well as a Capital Expenditure (CAPEX) plan in 2023, but fails to provide any details on how that will differ from its current maintenance efforts.	
RN-BVES-22-5.3.A.2	BVES states that it “has an ongoing program to assess and remediate noncompliant distribution poles” but does not provide any actual details on what that program consists of, if it differs outside of routine GO 95 and 165 efforts, or how BVES actually plans on targeting “priority pole replacements and remediations.”	7.3.3
RN-BVES-22-5.3.B	BVES plans on addressing its remaining conventional fuse replacements when performing other work in order to combine efforts and lower costs. While this could be more cost effective, it is not clear that this option will adequately cover the remaining conventional fuse replacements. Additionally, BVES has not shown that the completed replacements encompass the fuses identified as highest risk.	7.3.3
RN-BVES-22-5.3.C	BVES states that its “current SCADA system is inadequate,” and that it has established a Grid Automation Project, but the actual details on what this project entails are rudimentary. Aspects such as Wire Down Detection Relay Installment, Rapid Earth Fault Current Limiter (REFCL), and On-line Diagnostic Technology are not directly being explored and utilized by BVES, but instead holding out to observe the success of the pilots completed by the larger IOUs to determine which technology to move forward with.	7.3.3
RN-BVES-22-5.3.D	BVES~~’s~~ does not explain details on how its current operations covers maintenance of hotline clamps.	7.3
RN-BVES-22-5.3.E	BVES~~’s~~ does not provide details on its future tree attachment removals	7.3.3
RN-BVES-22-5.4.A	BVES does not currently tailor its detailed inspections to specifically target wildfire risk, instead relying on its existing GO 165 five-year inspections. BVES also has no plans to modify, monitor, nor audit the existing inspection program, although vaguely references that it “applies annual lessons learned or identified improvements and tracks developing inspection practices in the industry.” BVES does not explain how it goes about these improvements, and does not provide any examples.	7.3.4
RN-BVES-22-5.5.A	BVES uses the term “Enhanced Vegetation Management” (EVM) to describe numerous aspects of its VM program: fuel reduction, “collaborative measures with the USFS,” “off-schedule” risk-based inspections and VM activities, the contracting of a full-time utility forester, at-risk species remediation, strike potential tree removal, its vegetation inventory system, and equipment clearances.	7.3.5
RN-BVES-22-5.5.B	In Section 7.3.5.20, BVES states that it “currently does not remove trees on hillsides.” As such, Energy Safety is concerned that BVES is not meeting the requirements of	7.3.5

Issue ID	Issue	Applicable WMP Sections
	General Order (GO) 95, Rule 35 particularly regarding the removal of “dead, rotten or diseased trees… [that] may fall into a span of supply or communication lines.”	
RN-BVES-22-5.5.C	Condition BVES-R2 requires BVES to “provide detailed information on its fuels management and slash reduction practices.”75 Instead of describing its own fuels management practices, BVES instead discusses fuels management activities performed by other entities including Big Bear Fire Department and Bear Valley Community Service District.76 While it is laudable that the Big Bear Valley Community as a whole is addressing fuels management issue, Energy Safety expects BVES to detail its own fuels management activities and how it has contributed to the community fuels management activities it describes. BVES states that fuels management activities are required “by GOs and applicable standards.”77 General Orders (GOs) do not mention fuels and “slash” management; instead, these standards are outlined by the Board of Forestry’s Forest Practice Rules and Public Resources Code 4293; as such, Energy Safety is concerned that BVES is not implementing “applicable standards.”	7.3.5
RN-BVES-22-5.5.D	BVES-R7 requires BVES to discuss its system for tracking the compliance status of trees. Energy Safety acknowledges that BVES is still developing GIS and data tracking capabilities; BVES even states that vegetation management activities “will be tracked in BVES’s tree tracking program.”78 However, BVES does not demonstrate progress towards developing and implementing a tree tracking program and instead uses equivocating language stating, in regards to a vegetation inventory system, “BVES plans to integrate the contracted forester services into BVES vegetation management operations in the next year."79	7.3.5, 7.3.7
RN-BVES-22-5.6.A	BVES does not have specific crew designated for ignition prevention and suppression, instead relying on de-energizing work, and maintaining the ability to contract work out if deemed necessary. BVES did not provide details on the thresholds used to determine when ignition prevention and suppression work would be contracted.	7.3.6
RN-BVES-22-5.8.A	For many initiatives in Table 12 of its 2021 WMP Update, BVES states, “BVES has RSE calculations for its entire service territory, which is primarily Tier 2, some Tier 3 and no non-HFTD or Zone 1 areas. BVES will enhance its methodology to account for distinct RSE values for Tier 2 and Tier 3 in the future.” BVES must eliminate the usage of equivocating language, such as “in the future”, to make quantifiable, verifiable, and measurable commitments with respect to RSE improvements.	4.5.1
RN-BVES-22-5.8.B	For Capability 41c of the 2021 Maturity Survey, BVES selected “RSE estimates are verified by historical or experimental pilot data”80 for 2021 and “RSE estimates are	4.5.1

Issue ID	Issue	Applicable WMP Sections
	verified by historical or experimental pilot data and confirmed by independent experts or other utilities in CA”81 for 2023. However, BVES does not provide details in its 2021 WMP Update regarding the verification of RSE estimates	
RN-BVES-22-5.9.A	BVES does not adequately demonstrate progress and plans for next year in this mitigation initiative category	7.3.9
RN-BVES-22-5.9.B	BVES does not demonstrate the adequacy of its service restoration workforce within its 2021 WMP Update.	7.3.9, 5.4
RN-BVES-22-5.9.C	While BVES claims to engage with customers and communities regarding wildfire safety and PSPS preparedness year-round to increase awareness and support wildfire mitigation activities, it does not explain how it collects stakeholder feedback and how it incorporates them into both its community engagement efforts and wildfire mitigation planning.	7.3.9, 7.3.10
RN-BVES-22-5.10.A	BVES does not adequately demonstrate progress and plans for next year in this mitigation initiative category.	7.3.10
RN-BVES-22-6.A	BVES states that it is currently unable to project PSPS reduction metrics, indicating it “will assess the historical outlook of fire weather conditions over the last ten years and determine any instances where a PSPS activation would have been justified using BVES’s PSPS thresholds to assist in scenario development of forecasted risk.”	8.1
RN-BVES-22-6.B	BVES says it “will endeavor to follow lessons learned across California regarding the use of PSPS and will update its PSPS Plan and Emergency Response Plan accordingly.”83 This statement does not articulate an adequately proactive approach toward testing and articulating effectiveness of its PSPS and Emergency Response plans in upcoming fire seasons.	7.3.9

0. GLOSSARY OF DEFINED TERMS

Term	Definition
10-hour dead fuel moisture content	Moisture content of small dead vegetation (e.g., grass, leaves, which burn quickly but not intensely), which can respond to changes in atmospheric moisture content within 10 hours.
Access and functional needs populations	Per Public Utilities Code (Pub. Util. Code) § 8593.3 and D.19- 05-042, individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.
Authority Having Jurisdiction	AHJ, party with assigned responsibility, depending on location and circumstance.
Asset (utility)	Electric lines, equipment, or supporting hardware.
At-risk species	Species of vegetation that have an elevated risk of (1) coming into contact with powerlines, (2) causing an outage or ignition, and/or (3) easily ignitable and within close enough proximity to potential arcing, sparks and/or other utility equipment thermal failures. “At-risk species” must be a function of species-specific characteristics including growth rate, failure rate of limbs, trunk, and/or roots (as compared to other species), height at maturity, flammability, vulnerability to disease or insects, etc.
Baseline (ignition probability, maturity)	A measure, typically of the current state, which establishes a starting point for comparison with measures from other states.
Carbon dioxide Equivalent	Tons of greenhouse gases (GHG) emitted, multiplied by the global warming potential relative to carbon dioxide.
Circuit mile	The total length in miles of separate circuits regardless of the number of conductors used per circuit
Contractor	Any individual in the temporary and/or indirect employ of the utility whose limited hours and/or time-bound term of employment are not considered as “full-time” for tax and/or any other purposes.

Term	Definition
Critical facilities and infrastructure	For brevity in the WMP, "critical facilitates and infrastructure" may be shortened to "critical infrastructure" and/or "critical facilities" throughout the WMP. Critical facilities and infrastructure is defined in accordance with the definition adopted in D.19-05-042 and modified in D.20-05-051: those facilities and infrastructure that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de energization events. Namely: Emergency Services Sector Police Stations Fire Station Emergency Operations Centers Public safety answering points Government Facilities Sector Schools Jails and prisons Healthcare and Public Health Sector Public Health Departments Medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities (excluding doctor offices and other non-essential medical facilities) Energy Sector Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned utilities and electric cooperatives Water and Wastewater Systems Sector Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater Communications Sector Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals, and cellular sites Chemical Sector Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals (including Category N- Customers as defined in D.01-06-085) Transportation Sector Facilities associated with automobile, rail, aviation, major public transportation, and maritime transportation for civilian and military purposes
Customer hours	Total number of customers, multiplied by the average number of hours (e.g., of power outage).

Term	Definition
Data cleaning	Calibrating raw data to remove errors (including typographical and numerical mistakes).
Dead fuel moisture content	Moisture content of dead vegetation, which responds solely to current environmental conditions and is critical in determining fire potential.
Detailed inspection	In accordance with GO 165, an inspection where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
Enhanced Inspection	Inspection whose frequency and thoroughness exceeds the requirements of the detailed inspection, particularly if driven by risk calculations.
Enterprise System	A centralized information system that ensures data may be shared throughout all functional levels and management hierarchies of an organization, as needed.
Evacuation impact	Number of people evacuated, with the duration for which they are evacuated, from homes and businesses, due to wildfires.
Evacuation zone	Areas designated by CAL FIRE and local fire agency evacuation orders, to include both “voluntary” and “mandatory” in addition to other orders such as “precautionary” and “immediate threat”.
Fire Season	The time of year that wildfires are most likely to take place for a given geographic region due to historical weather conditions, vegetative characteristics and impacts of climate change. Goals and targets which have milestones related to the onset, duration, or end of “fire season” or “height of fire season” must be accompanied with calendar dates.
Frequently de-energized circuit	A circuit which has been de-energized pursuant to a de- energization event to mitigate the risk of wildfire three or more times in a calendar year.
Fuel density	Mass of fuel (vegetation) per area which could combust in a wildfire.
Fuel management	Removing, thinning, or otherwise altering vegetation to reduce the potential rate of propagation or intensity of wildfires.
Fuel moisture content	Amount of moisture in a given mass of fuel (vegetation), measured as a percentage of its dry weight.
Full-time employee	Any individual in the ongoing and/or direct employ of the utility whose hours and/or term of employment are considered as “full-time” for tax and/or any other purposes.
GO 95 nonconformance	Condition of a utility asset that does not meet standards established by General Order 95.
Greenhouse gas (GHG) emissions	Health and Safety Code 38505 identifies seven greenhouse gases that ARB is responsible to monitor and regulate in order to reduce emissions: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and nitrogen trifluoride (NF_3).

Term	Definition
Grid hardening	Actions (such as equipment upgrades, maintenance, and planning for more resilient infrastructure) taken in response to the risk of undesirable events (such as outages) or undesirable conditions of the electrical system in order to reduce or mitigate those events and conditions, informed by an assessment of the relevant risk drivers or factors.
Grid topology	General design of an electric grid, whether looped or radial, with consequences for reliability and ability to support de- energization (e.g., being able to deliver electricity from an additional source).
High Fire Threat District (HFTD)	Per D.17-01-009, areas of the State designated by the Office of Energy Infrastructure Safety and CAL FIRE to have elevated wildfire risk, indicating where each utility must take additional action (per GO 95, GO 165, and GO 166) to mitigate wildfire risk.
Highly rural region	In accordance with 38 CFR 17.701, "highly rural" must be defined as those areas with a population of less than 7 persons per square mile. For the purposes of the WMP, "area" must be defined as census tracts.
High Wind Warning (HWW)	Level of wind risk from weather conditions, as declared by the National Weather Service. For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[7]
HWW overhead (OH) Circuit Mile Day	Sum of overhead circuit miles of utility grid subject to High Wind Warnings (HWW, as defined by the National Weather Service) each day within a given time period, calculated as the number of overhead circuit miles that are under an HWW multiplied by the number of days those miles are under said HWW. For example, if 100 overhead circuit miles are under an HWW for 1 day, and 10 of those miles are under HWW for an additional day, then the total HWW OH circuit mile days would be 110.
Ignition probability	The relative possibility that an ignition will occur, probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certainty there is that the event will occur. (Often informally referred to as likelihood or chance).
Ignition-related deficiency	Any condition which may result in ignition or has previously resulted in ignition, even if not during the past five years.
Impact/consequence of ignitions	The effect or outcome of a wildfire ignition upon objectives, which may be expressed by terms including, although not limited to, maintaining health and safety, ensuring reliability, and minimizing economic and/or environmental damage.
Initiative	Measure or activity proposed or in process designed to reduce the consequences and/or probability of wildfire or PSPS.
Inspection protocol	Documented procedures to be followed in order to validate that a piece of equipment is in good condition and expected to operate safely and effectively.

[7] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

Term	Definition
Invasive species	A species that is: 1) non-native (or alien) to the ecosystem under consideration and 2) whose introduction causes or is likely to cause economic or environmental harm or harm to human health.
Level 1 finding	In accordance with GO 95, an immediate safety and/or reliability risk with high probability for significant impact.
Level 2 finding	In accordance with GO 95, a variable (non-immediate high to low) safety and/or reliability risk.
Level 3 finding	In accordance with GO 95, an acceptable safety and/or reliability risk.
Life expectancy	Anticipated years that a piece of equipment can be expected to meet safety and performance requirements.
Limited English Proficiency (LEP)	Populations with limited English working proficiency based on the International Language Roundtable scale.
Line miles	The number of miles of transmission and/or distribution line. Differs from circuit miles because individual circuits, such as the two circuits of a double-circuit line, are not counted separately in circuit miles but are counted as separate total miles of line.
Live fuel moisture content	Moisture content within living vegetation, which can retain water longer than dead fuel.
Lost energy	Energy that would have been delivered if not for an outage.
Major roads	Interstate highways, U.S. highways, state and county routes.
Match drop simulation	Wildfire simulation method that takes an arbitrary ignition and forecasts propagation and consequence/impact.
Member of the public	Any individual not employed by the utility.
Multi-attribute value function	Risk calculation methodology introduced during CPUC's S- MAP and RAMP proceedings.
Near miss	Previously used to define an event with probability of ignition. Redefined under “Risk event.”
Need for PSPS	When the utility’s criteria for utilizing PSPS are met.
Noncompliant clearance	Rights-of-way whose vegetation is not trimmed in accordance with the requirements of GO 95.
Outages of the type that could ignite a wildfire	Outages that, in the judgement of the utility, could have ignited a wildfire.
Outcome metrics	Measurements of the performance of the utility and its service territory in terms of both leading and lagging indicators of wildfire, PSPS, and other consequences of wildfire risk, including the potential unintended consequences of wildfire mitigation work, such as acreage burned by utility-related ignitions.
Overcapacity	When the energy transmitted by utility equipment exceeds that of its nameplate capacity.

Term	Definition
Patrol inspection	In accordance with GO 165, a simple visual inspection of applicable utility equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
Percentile conditions	Top X% of a particular set (e.g., wind speed), based on a historical data set with sufficient detail. For example, "Top 95 percentile wind speeds in the last 5 years" would refer to the 5% of avg daily wind speeds recorded by each weather station. If 1,000 weather stations recorded average daily wind speeds over 10 days, then the 95th percentile wind speed would be the top 5% of weather station-days. In this example, there will be 10 days each with 1,000 weather station reports and a total of 10,000 weather station-days, so 50 observations will be in the top 5%. The lowest wind speed in this top 5% would be the "95th percentile wind speed".
Planned outage	Electric outage announced ahead of time by the utility.
Preventive maintenance (PM)	The practice of maintaining equipment on a regular schedule, based on risk, elapsed time, run-time meter readings, or number of operations. The intent of PM is to "prevent" maintenance problems or failures before they take place by following routine and comprehensive maintenance procedures. The goal is to achieve fewer, shorter, and more predictable outages.
Priority essential services	Critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies.
Program targets	Quantifiable measurements of activity identified in WMPs and subsequent updates used to show progress towards reaching the objectives.
Progress metrics	Measurements that track how much utility wildfire mitigation activity has changed the conditions of utility wildfire risk exposure or utility ability to manage wildfire risk exposure, in terms of leading indicators of ignition probability and wildfire consequences.
Property	Private and public property, buildings and structures, infrastructure, and other items of value that are destroyed by wildfire, including both third-party property and utility assets.
PSPS event	Defined as the time period from the first public safety partner notified of a planned public safety de-energization to the final customer re-energized.
PSPS risk	The potential for the occurrence of a PSPS event expressed in terms of a combination of various outcomes of the event and their associated probabilities.
PSPS weather	Weather that exceeds a utility's risk threshold for initiating a PSPS.
Red Flag Warning (RFW)	Level of wildfire risk from weather conditions, as declared by the National Weather Service. For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[8]

[8] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

Term	Definition
RFW OH Circuit Mile Day	Sum of overhead circuit miles of utility grid subject to Red Flag Warning each day within a given time period, calculated as the number of overhead circuit miles that are under an RFW multiplied by the number of days those miles are under said RFW. For example, if 100 overhead circuit miles are under an RFW for 1 day, and 10 of those miles are under RFW for an additional day, then the total RFW OH circuit mile days would be 110.
Risk event	An event with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition. The following risk events all qualify as risk events: 1. Ignitions 2. Outages not caused by vegetation 3. Vegetation-caused outages 4. Wire-down events 5. Faults 6. Other risk events with potential to cause ignitions
Risk event simulation	Simulation of what the consequence would have been of an ignition had it occurred.
Risk-spend efficiency (RSE)	An estimate of the cost-effectiveness of initiatives, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs. For ongoing initiatives, the RSE can be calculated by determining the “marginal benefit” of additional spending in the ongoing initiative. For example, the RSE of an ongoing initiative could be calculated by dividing the mitigation risk reduction benefit from a 5% increase in spend by the cost associated with a 5% increase in spend.
Rule	Section of public utility code requiring a particular activity or establishing a particular threshold.
Run-to-failure	A maintenance approach that replaces equipment only when it fails.
Rural region	In accordance with GO 165, "rural" must be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, “area” must be defined as census tracts.
Safety Hazard	A condition that poses a significant threat to human life or property.
Simulated wildfire	Propagation and impact/consequence of a wildfire ignited at a particular point ('match drop'), as simulated by fire spread software.
Span	The space between adjacent supporting poles or structures on a circuit consisting of electric lines and equipment. "Span level" refers to asset-scale granularity.
System Average Interruption Duration Index (SAIDI)	System-wide total number of minutes per year of sustained outage per customer served.

Term	Definition
Third-party contact	Contact between a piece of electrical equipment and another object, whether natural (tree branch) or human (vehicle).
Time to expected failure	Time remaining on the life expectancy of a piece of equipment.
Top 30% of proprietary fire potential index	Top 30% of FPI or equivalent scale (e.g., "Extreme" on SCE's FPI; "extreme", 15 or greater, on SDG&E's FPI; and 4 or above on PG&E's FPI).
Trees with strike potential / hazard trees	A tree within or adjacent to the utility right-of-way that has a structural defect or lean that makes it likely to fail in whole or in part and contact electrical equipment or facilities.[9]
Unplanned outage	Electric outage that occurs with no advance notice from the utility (e.g., blackout).
Urban region	In accordance with GO 165, "urban" must be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.
Utility-ignited wildfire	Ignitions involving utility infrastructure or employees, including all ignitions determined by AHJ investigation to originate from utility infrastructure or employees.
Vegetation management	Trimming, removal, and other remediations of vegetation used to maintain utility ROW and reduce the risk of outages, ignitions, and other disruption and danger.
Vegetation risk index	Risk index indicating the probability of vegetation-caused outages and/or ignitions along a particular circuit, based on the vegetation species, density, height, growth rate, etc.
Weather normalization	Adjusting metrics based on relative weather risk factors or indices
Wildfire impact/ consequence	The effect or outcome of a wildfire affecting objectives, which may be expressed, by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Wildfire risk	The potential for the occurrence of a wildfire event expressed in terms of ignition probability, wildfire impact/consequence.
Wildfire-only WMP programs	Activities, practices, and strategies that are only necessitated by wildfire risk, unrelated to or beyond that required by minimum reliability and/or safety requirements. Such programs are not indicated or in common use in areas where wildfire risk is minimal (e.g., territory with no vegetation or fuel) or under conditions where wildfires are unlikely to ignite or spread (e.g., when rain is falling).
Wildland urban interface (WUI)	A geographical area identified by the state as a "Fire Hazard Severity Zone", or other areas designated by the enforcing agency to be a significant risk from wildfires, established pursuant to Title 24, Part 2, Chapter 7A.

[9] "Danger tree" is more specifically defined in California Code of Regulation Title 14 § 895.1

Term	Definition
Wire down	Instance where an electric transmission or distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object.

1 PERSONS RESPONSIBLE FOR EXECUTING THE WMP

Provide an accounting of the responsibilities of the responsible person(s) executing the plan, including:

Executive level with overall responsibility

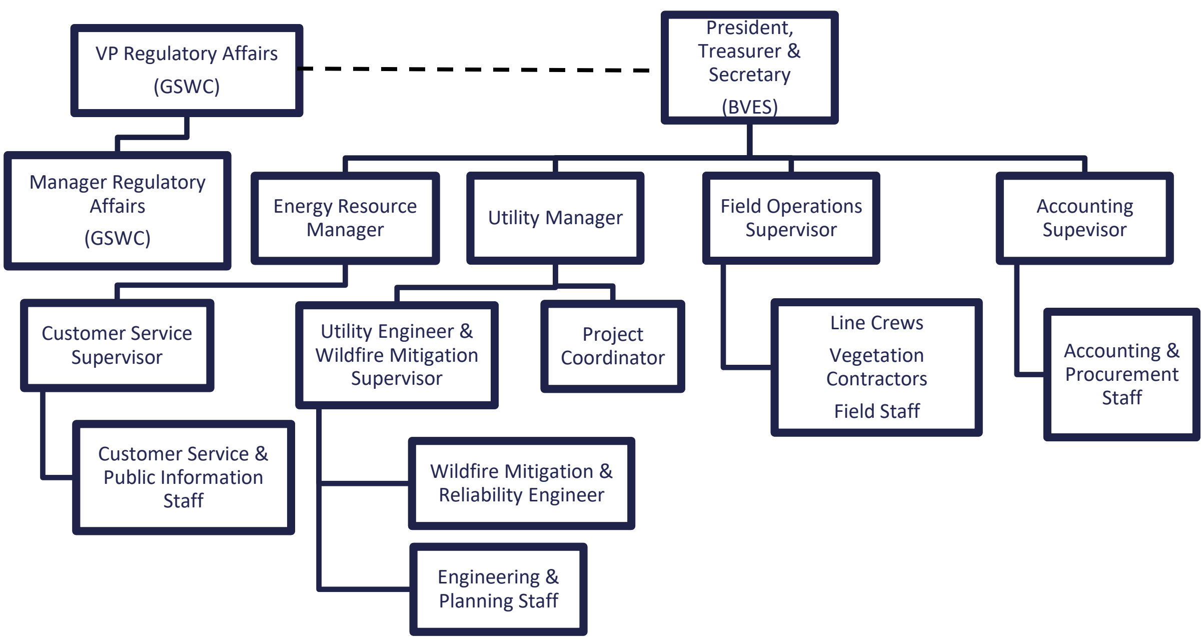
Program owners specific to each component of the plan

Title, credentials, and components of responsible person(s) must be released publicly, but other contact information may be provided in a redacted file attached to the WMP submission.[10]

The President, Treasurer, & Secretary oversees project implementation and ensures staff follow established procedures and protocols. The Utility Manager manages the execution of the performance monitoring including providing guidance to staff and leading the development of reports. The staff responsible for each WMP component aggregate relevant metrics and performance targets at the direction of the Utility Manager, who manages the expenditure tracking and planning arrangements of initiatives. The Customer Service Supervisor holds responsibility for tracking customer-related metrics and PSPS program implementation, and customer engagement related to WMP and PSPS activities.

Figure 1.1-1 below outlines the BVES WMP organization. Further descriptions of the roles and responsibilities are provided below.[11]

Figure 1.1-1: BVES Wildfire Mitigation Plan Organization



[10] On December 15, 2021, the OEIS issued the final, adopted versions of the 2022 WMP Update Guidelines Template (Guidelines) under Energy Safety, Attachments 1 and 2 form the basis for developing the WMP structure. Energy Safety issued the initial draft on December 2, 2021 and received comments through December 2, 2021. The OEIS issued the reply comments and published revision on December 13, 2021 with a formal adoption of the Guidelines on December 14, 2021. The prompts herein are italicized and in blue text to differentiate guidelines from BVES's response.

[11] This 2022 WMP Update filing notes several title changes and new positions targeting wildfire mitigation initiative implementation as a result of the corporate change effective July 1, 2020. Pursuant to (Decision) D. 19-12-039, BVES (U 913-E) filed notice of its change of name to Bear Valley Electric Service, Inc. on January 6, 2021 under Rulemaking (R.) 18-10-007. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M359/K001/359001306.PDF.

Executive-Level Owner with Overall Responsibility

The following Executive Level contact is responsible for overall monitoring and execution of the BVES WMP:

Name and title: Paul Marconi, President, Treasurer, & Secretary BVES is responsible for the overall management of BVES and is directly responsible for ensuring all of the WMP elements are executed as intended. The President, Treasurer, & Secretary shall provide the Board of Directors' Safety Committee periodic updates on safety issues, plan execution; identify any problems, delays in schedule, and resource shortfalls; and propose solutions to issues and problems. The President, Treasurer & Secretary shall also keep the Vice President, Regulatory Affairs of Golden States Water Company (GSWC) informed of all compliance and regulatory affairs issues regarding the plan. The President, Treasurer, & Secretary shall communicate the WMP to BVES staff and hold staff accountable for executing their portions of the WMP including PSPS activation decisions. The President, Treasurer, & Secretary shall ensure the applicable portions of the WMP is communicated to local government and agencies, key stakeholders, customers, and the general public. The President, Treasurer, & Secretary is responsible for ensuring lessons learned and metrics from the current WMP are incorporated into future WMPs as appropriate.

Email: paul.marconi@bvesinc.com

Phone number: (909)-202-9539

Program Owners Specific to Each Section of the Plan

Key utility staff execute and implement this WMP working closely with public safety, local agencies and governments, fire, forestry management, first responders, and customers to enable information dissemination to vested stakeholders. BVES also retains experienced and qualified third-party contractors to assist in the performance of the WMP.

Table 1.1-1 outlines leadership roles regarding implementation and monitoring of the WMP and their relevant responsibilities.

Table 1.1-1: Program Owners Specific to Each Section of the Plan

Name	Title	Email	Phone Number	Component
Section 1: Persons Responsible for Executing the Plan				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 2: Adherence to Statutory Requirements				
Jon Pierotti	Vice President, Regulatory Affairs	Jon.Pierotti@gswater.com	909.394.3600 x656	Entire Section
Nguyen Quan	Manager, Regulatory Affairs	Nguyen.Quan@gswater.com	909.394.3600 x664	Entire Section
Section 3: Actuals and Planned Spending				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section

Name	Title	Email	Phone Number	Component
Section 4: Lessons Learned and Risk Trends				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 5: Inputs to the Plan and Directional Vision				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Section 5.1 - Section 5.3
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909 253-8966	Section 5.4
Section 6: Metrics and Underlying Data				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909 253-8966	Entire Section
Section 7: Mitigation Initiatives				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909 253-8966	Entire Section
Section 8: Public Safety Power Shutoff				
Sean Matlock	Energy Resource Manager	Sean.Matlock@bvesinc.com	909.522.1913	Entire Section
Section 9: Appendix				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Entire Section

1.1 Verification

Complete the following verification for the WMP submission:

(See Rule 1.11)

(Where Applicant is a Corporation)

I am an officer of the applicant corporation herein and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true. I have reviewed this WMP and attest to its completeness and accuracy.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 29, 2022 at San Dimas, California.

Paul Marconi, President, Treasurer, and

Secretary of Bear Valley Electric Service, Inc.

2 ADHERENCE TO STATUTORY REQUIREMENTS

Section 2 comprises a "checklist" of the CPUC Code Sec. 8386 (c) requirements and subparts. The utility is required to both affirm that the WMP addresses each requirement AND cite the section and page number where statutory compliance is demonstrated fully. Citations are required to use cross-referencing with hyperlinks.[12]

If multiple WMP sections address a specific requirement, then reference to all relevant sections with a brief indication of information provided in each section must be provided. The table must include each section reference separated by semi-colon (e.g., Section 5, pg. 30-32 (workforce); Section 7, pg. 43 (mutual assistance)) where appropriate, and associated hyperlinks to the referenced section.

Table 2.1-1: Statutory Compliance Matrix

Requirement	Description	WMP Section & Page Number
1	An accounting of the responsibilities of persons responsible for executing the plan	Section 1; pg.10
2	The objectives of the plan	Section 5.2; pg. 88
3	A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks	Sections 7.1, 7.3; pg. 116 and 136
4	A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics	Section 6; pg. 111, Section 5.2; pg. 88, and the Q4 2021 QDR Appendix D (also submitted as Attachment A concurrently with this WMP 2022 Update)
5	A discussion of how the application of previously identified metrics to previous plan performances has informed the plan	Section 4.1; pg. 20 Section 4.5.1; pg. 47 and the Q4 2021 QDR Appendix D (also submitted as Attachment A concurrently with this WMP 2022 Update)
6	Protocols for disabling reclosers and de-energizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and de-energizing portions of the electrical distribution system that consider the impacts on all of the aspects listed in PU Code 8386c	Section 8.2; pg. 294 Appendix B; pg. 1. See also Table 4.2-3; pg.34

[12] Note: Energy Safety reserves the right to automatically reject a WMP that does not provide substantiation for statutory compliance or does not provide citations to appropriate sections of the WMP.

Requirement	Description	WMP Section & Page Number
7	Appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines, including procedures for those customers receiving a medical baseline allowance as described in paragraph (6). The procedures shall direct notification to all public safety offices, critical first responders, health care facilities, and operators of telecommunications infrastructure with premises within the footprint of potential de-energization for a given event	Sections 8.2; pg. 294, Section 8.4; pg. 315. Appendix B; pg. 1.
8	Identification of circuits that have frequently been de- energized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines	Section 8.6; pg. 321
9	Plans for vegetation management	Sections 5.3; pg. 89, Section 5.4.1; pg. 100, 7.3.2.5; pg. 157
10	Plans for inspections of the electrical corporation’s electrical infrastructure	Sections 5.3; pg. 89, Section 5.4.3, pg. 103, 7.3.2.5; pg. 157
11	Protocols for the de-energization of the electrical corporation’s transmission infrastructure, for instances when the de-energization may impact customers who, or entities that, are dependent upon the infrastructure	Section 8; pg. 290, Appendix B; pg. 1.
12	A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation’s service territory, including all relevant wildfire risk and risk mitigation information that is part of the Safety Model Assessment Proceeding and the Risk Assessment Mitigation Phase filings	Sections 4.2; pg. 24, Section 4.2.1; pg. 36, Section 4.3; pg. 42, Section 4.6; pg. 78
13	A description of how the plan accounts for the wildfire risk identified in the electrical corporation’s Risk Assessment Mitigation Phase filing	Section 4.2; pg. 24, Section 4.2.1; pg. 36
14	A description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement	Sections 5.3; pg. 89, Section 7.1; pg. 116, Section 7.3.2; pg. 147

Requirement	Description	WMP Section & Page Number
15	A description of where and how the electrical corporation considered undergrounding electrical distribution lines within those areas of its service territory identified to have the highest wildfire risk in a commission fire threat map	Sections 5.3; pg. 89, Section 6.8.2; pg.114, Section 9.4; pg. 341
16	A showing that the electrical corporation has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the electrical corporation	Section 5.4; pg. 99
17	Identification of any geographic area in the electrical corporation's service territory that is a higher wildfire threat than is currently identified in a commission fire threat map, and where the commission must consider expanding the high fire threat district based on new information or changes in the environment	Sections 4.2; pg. 24, Section 4.2.1; pg. 36, Section 4.3; pg. 42
18	A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the commission determines otherwise	Section 4.2; pg. 24
19	A description of how the plan is consistent with the electrical corporation's disaster and emergency preparedness plan prepared pursuant to Section 768.6, including plans to restore service and community outreach	Section 7.3.9; pg. 271 and Appendix B; pg. 1, Appendix C; pg. 388
20	A statement of how the electrical corporation will restore service after a wildfire	Section 8.2; pg. 294 and Appendix B; pg. 1 Appendix C; pg. 388
21	Protocols for compliance with requirements adopted by the commission regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to electrical corporation representatives, and emergency communications	Sections 8.4; pg. 315, Section 7.3.9; pg. 271, and Appendix B; pg. 1 Appendix C; pg. 388
22	A description of the processes and procedures the electrical corporation will use to do the following: Monitor and audit the implementation of the plan. Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies. Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.	Section 7.2; pg. 133

3 ACTUALS AND PLANNED SPENDING FOR MITIGATION PLAN

3.1 Summary of WMP Initiative Expenditures

Table 3.1-1 summarizes the projected costs (in thousands of US $) per year over the three- year WMP cycle, including actual expenditures for past years. In Table 3.1-2, break out projected costs per category of mitigations, over the three-year WMP plan cycle. In reporting "planned" expenditure, use data from the corresponding year's WMP or WMP Update (i.e., 2020 planned expenditure must use 2020 WMP data). The financials represented in the summary tables below equal the aggregate spending listed in the mitigations financial tables reported quarterly. Nothing in this document is required to be construed as a statement that costs listed are approved or deemed reasonable if the WMP is approved, denied, or otherwise acted upon.

Table 3.1-1: Summary of WMP Expenditures - Total

Year	Spend in Thousands of $USD
2020 Planned	$11,417
2020 Actual	$9,154
2020 Difference	($2,262)
2021 Planned	$15,218
2021 Actual	$12,088
2021 Difference	($3,130)
2022 Planned	$16,240
2020-22 Planned (With 2020 and 2021 Actual)	$42,875

Table 3.1-2: Summary of WMP Expenditures by Category

WMP Category	2020			2021			2022	2020-2022 Planned (w/2020 and 2021 Actual)
	Planned	Actual	Δ	Planned	Actual	Δ	Planned	
Risk & Mapping	$0.00	$0.00	$0.00	$57.14	$57.14	($0.00)	$85.50	$142.64
Situational Awareness	$313.86	$54.24	($259.62)	$85.00	$161.28	$76.28	$304.50	$520.02
Grid Design and System Hardening	$7,923.90	$6,689.93	($1,233.97)	$11,623.71	$8,398.92	($3,224.79)	$12,765.31	$27,854.16
Asset Management and Inspections	$287.21	$143.60	($143.61)	$285.00	$182.25	($102.76)	$223.80	$549.64
Vegetation Management	$2,845.25	$2,254.72	($590.54)	$3,069.67	$3,113.78	$44.11	$2,652.82	$8,021.31
Grid Operations	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Data Governance	$46.38	$0.00	($46.38)	$0.00	$0.00	$0.00	$0.00	$0.00
Resource Allocation	$0.00	$0.00	$0.00	$22.86	$22.86	$0.00	$50.68	$73.54
Emergency Planning	$0.00	$11.89	$11.89	$59.50	$139.38	$79.88	$143.56	$294.84
Stakeholder Cooperation and Community Engagement	$0.00	$0.00	$0.00	$14.79	$11.91	($2.88)	$13.65	$25.56
Total	$11,416.61	$9,154.37	($2,262.23)	$15,217.67	$12,087.51	($3,130.15)	$16,239.82	$37,481.71

3.2 Summary of Ratepayer Impact

For each of the years in Table 3.2-1, report the actual and projected cost increases to ratepayers due to utility-related ignitions and wildfire mitigation activities engaged. For past years, account for all expenditures incurred in that year due to utility-related ignitions and wildfire mitigation activities. Below the table, describe the methodology behind the calculations.

The table below presents incremental costs impacting customers with respects to utility-related ignitions and accumulated wildfire mitigation activities. BVES has not reported any ignition events over the last five years, yielding no direct impact to ratepayers.

BVES has disaggregated expenditures based on WMP activities and corresponding initiative categories. The methodology is based on a calculation that separates planned and executed spend from the general rates category. This is due to several costs and partial expenditures being captured in other balancing accounts for General Rate Case (GRC) accounting or through uniform system accounting of Federal Energy Regulatory Commission accounts. Due to the recent remapping of costs and granular disaggregation of initiative performance activities, BVES applied a calculation to each of the initiatives, which have corresponding amounts reflected in general rates and thus applied the incremental value of mitigation initiatives into the rate calculation below.

Table 3.2-1: WMP Electricity Cost Increase to Ratepayers

Outcome Metric Name	Annual Performance						Unit(s)
	Actual					Projected	
	2017	2018	2019	2020	2021	2022	
Increase in electric costs to ratepayer due to utility-related wildfires (total)	$0	$0	$0	$0	$0	$0	Dollar value of average monthly rate increase attributable to utility-ignited wildfires per year (e.g., $3/month on average across customers for utility-ignited wildfires occurring in 20XX)
Increase in electric costs to ratepayer due to wildfire mitigation activities (total)	N/A	N/A	$0.01184/kWh	$0.02279/kWh	$0.03180/kWh	$0.03367/kWh	Dollar value of average monthly rate increase attributable to WMPs per year

4 LESSONS LEARNED AND RISK TRENDS

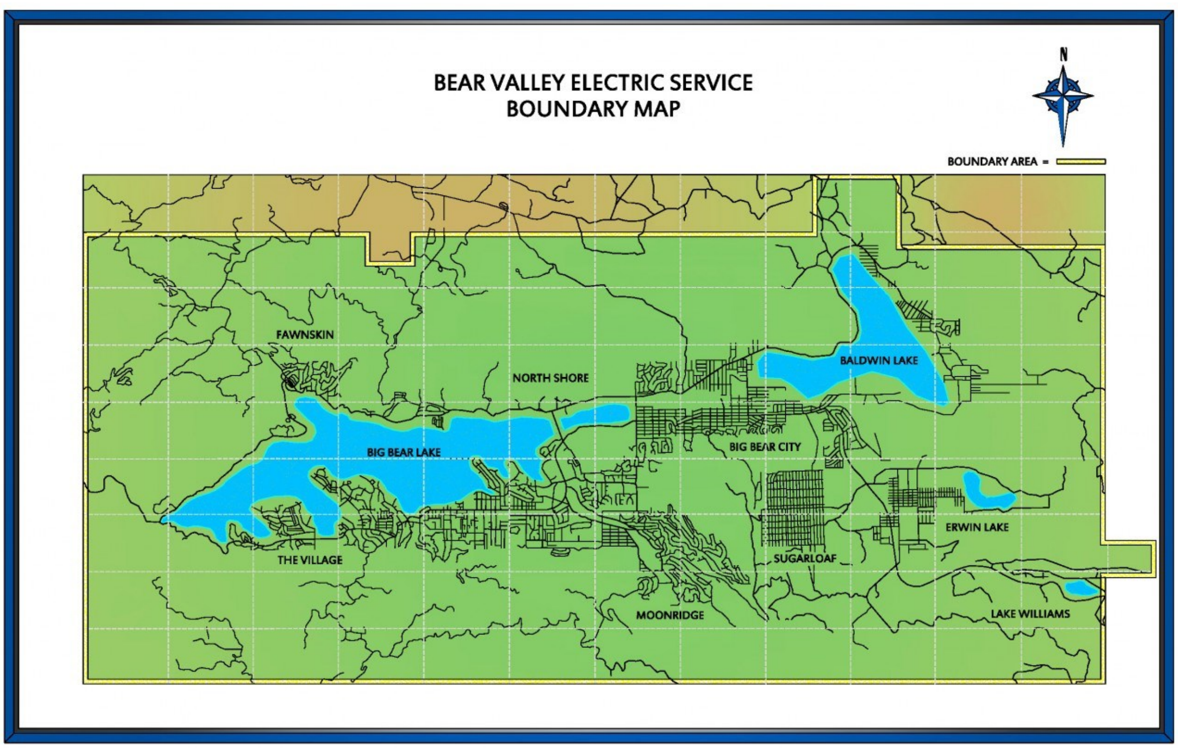
4.1 Lessons Learned: How Tracking Metrics on the 2020 and 2021 Plans Informed the 2022 Plan Update

Describe how the utility's plan has evolved since the 2020 WMP and 2021 WMP Update submissions. Outline any major themes and lessons learned from the 2020 and 2021 plans, and subsequent implementation of the initiatives. In particular, focus on how utility performance against the metrics used has informed the 2022 WMP Update. Include an overview map of the utility's service territory. If any of the lessons learned are derived from data, include visual/graphical representations of this/these lesson(s) learned.

The 2022 WMP Update includes reports on actions undertaken over 2021 including activities relating to any deficiencies issued by the OEIS. In addition, the Plan has evolved significantly over the 2020 and 2021 WMP Update submissions through new templatized processes, enhanced data collection and governance, and successful execution of high priority initiatives.

BVES has worked to adhere to the detailed requests and quantitative target setting to align with prioritized mitigation efforts. The 2022 WMP Update includes improvements such as enhanced mapping capabilities as BVES digitize its asset and inspection practices, more meaningful metric tracking calibrated across multiple internal reporting processes and platforms, and climate-driven ignition probability maps that BVES will use to inform future initiative planning for areas of greatest wildfire risk.

Figure 4.1-1: BVES Service Territory Map



Major themes and lessons learned from the prior WMPs, periodic submissions, and experience with mitigation efforts provide valuable insight into BVES's continuous improvement efforts. BVES experienced great success in executing and implementing mitigation strategies and has not recorded a utility-ignited wildfire incident or activated a PSPS. Issues or delays in execution are addressed upon identification throughout the year. BVES continues to provide an open line of communication among the WMP responsible personnel up to and including the President. If a change of strategy is warranted, the appropriate department heads discuss potential actions and monitor any changes. Each quarter, the President, Secretary, & Treasurer meets with the Safety Board Committee, which encompasses governing body members of the Company, to discuss any issues identified during the prior quarter and will discuss proposed alternatives in strategy. This process enables a feedback loop for continuous improvement.

Major themes and lessons learned from the prior WMP Update influence this year's initiatives and metric planning. BVES will continue to investigate and learn from these themes and those that arise in the coming year. **Table 4.1-1** provides a summary of lessons learned in 2020 and 2021 and corresponding changes in the BVES 2022 WMP Update.

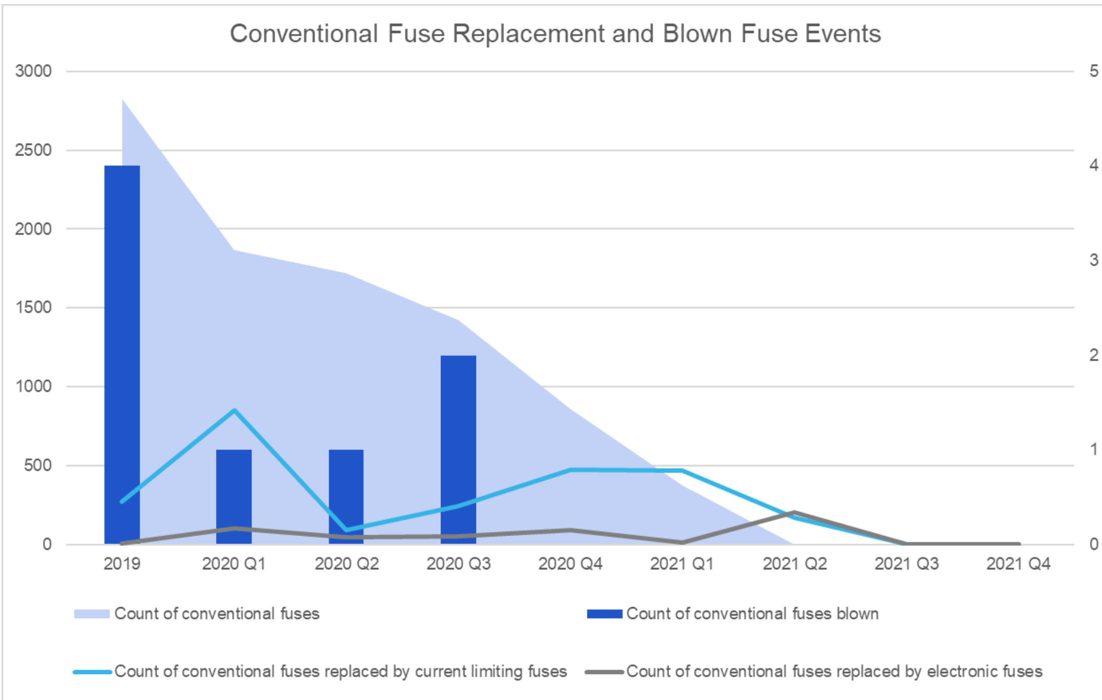
Table 4.1-1 Summary of WMP Lessons Learned in 2020 and 2021

WMP Category	2020/2021 Lesson Learned	2022 WMP Update
Resource Allocation Methodology	Internal and external resources are required to fill key roles for WMP implementation	BVES hired direct roles to oversee prioritized aspects of the WMP program and processes. However, external consultant support is still a necessity for some areas.
Situational Awareness, Grid Design and System Hardening	External constraints related to federally managed or private lands impact initiative schedules and implementation and require active management	Execution of system hardening, and situational awareness initiatives resulted in some minor delays over the 2020 – 2021 timeframe. For example, BVES was able to complete the last two weather station installations in early 2021 after significant delays. Similarly, BVES has pushed out the schedule for its energy storage project due to land siting issues.
Grid Design and System Hardening	Replicated initiatives among California IOUs on similar time schedules causes material procurement delays and increased costs for system hardening initiatives such as covered conductor hardening	BVES has worked to better account for its mitigation measures under varying WMP mitigation category initiative listings, which results in slight deviations from planned expenditure. These issues are addressed as a revised accounting methodology has been applied to align to the latest OEIS issued initiative listing. BVES has been able to move to a year-ahead purchasing schedule for system hardening stock based off of initiative efficiencies and valuable historic replacement trends. Projections on stock have also improved.
Grid Design and System Hardening	Winter months snow loading requires careful planning of field work	Due to the topography and climate of the region, BVES experiences seasonal delays due to inability to perform field work during winter weather conditions. As substantive mitigation measures are deployed within the earlier years of the WMP program, this concern will lessen, and strategic operations can be better refined to avoid such harsh winter conditions.
Risk Assessment and Mapping	Determination of quantitatively driven metrics and risk spend efficiency (RSE) values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES was not able to update all of its RSE values in 2021 within the quarterly data report (QDR) updates due to initiative recategorization and lack of sustained metrics, which result in meaningful baseline data metrics.

WMP Category	2020/2021 Lesson Learned	2022 WMP Update
Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES has worked to deploy grid hardening activities on prioritized circuits to reduce future risk events. The intent is to lower the number of risk events captured in the QDR metrics as demonstrated spark-resistant measures are applied to the system. One example is realized through the number of blown fuse events recorded over time. BVES completed its program to replace all conventional fuses with current limiting and electronic fuses. The resulting metrics indicate that this effort is already reducing blown fuse events, which is a significant ignition risk factor. See **Figure 4.1-2** below.
Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	Apart from blown fuse tracking, overall risk events have not begun to indicate a downward trend in activity, as BVES works in its third year of hardening efforts. The anticipated result would illustrate, over time, fewer risk events on the system year over year. As risk predictions and recorded incidents continue to determine the baseline, BVES will track these metrics for future WMP updates. See **Figure 4.1-3** below.
Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	As part of several hardening initiatives, including evacuation route projects, BVES has replaced an increased number of poles and determined needs for fire resistant wrapping as inspection programs are carried out. While **Table 4.1-2** does not indicate a scaled trend of meaningful metrics, it does convey increased intrusive inspections of poles for remediation or replacement, for which BVES has met its internal targets.
Risk Assessment and Mapping	Improved data tracking, equipment inventorying practices, and refined definitions for specific metrics leads to instances of impacted quantitative metrics	In preparation for this filing, BVES reviewed the completed 2021 metrics, as well as its projects initiated to mitigate against wildfire ignitions and damage to BVES equipment and facilities, to determine whether current scheduling and planned execution is sufficient in this 2022 WMP Update. BVES has also been able to achieve greater granularity in weather data with no identified increase in severe weather. Due to better data tracking, equipment inventory practices, and refined definitions for specific metrics, BVES has seen instances of impacted quantitative metrics from 2020 to 2021. In years prior, BVES had not been able to effectively leverage existing data.
Risk Assessment and Mapping	The ignition risk and consequence mapping project has provided useful insight into simulations of fire threats	The modeling exercise will influence future planning as current initiatives are carried out. The models and maps were finalized in late 2021, providing an initial screening into areas of greatest concern beyond the high fire-threat district (HFTD) and wildland urban interface (WUI) designations. In future reporting and mitigation measure determination, these maps will

WMP Category	2020/2021 Lesson Learned	2022 WMP Update
		contribute to navigate decision-making along with existing risk modeling tools.
Stakeholder Cooperation and Community Engagement	Apply findings from public safety partners and community coordination throughout the year to inform future planning	Drawing upon lessons learned from other California utilities, BVES has increased its community engagement activities over 2021 from 2020 as well as engaging more broadly with the direct public safety partners within the service area.

Figure 4.1-2: Blown Fuse History vs. Conventional Fuse Replacement Program



The left-hand Y-Axis represents the count of conventional fuses, and the right-hand Y-Axis represents the count of conventional blown fuses. All three trend lines values are determined by the left-hand Y-axis.

Figure 4.1-3: Risk Events (Recorded in QDR)

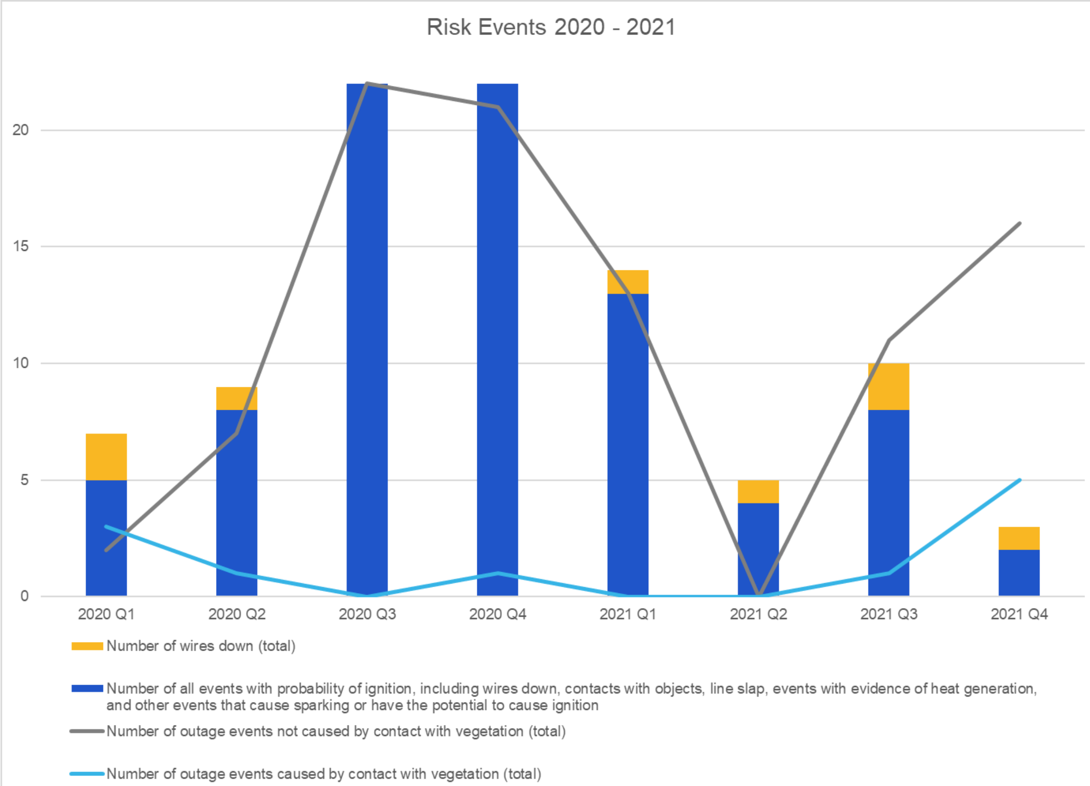


Table 4.1-2: Pole Assessments and Remediation/Replacement

Year	Poles Assessed (Total)	Poles Failing Assessment	Remediated Poles as a Result of Failed Assessment	Poles Replaced (Total)	Poles Intrusively Inspected	Poles Failing Intrusive Inspection
2019	1588	393	66	305	48	3
2020	191	107	7	236	0	0
2021	557	279	7	216	876	28

4.2 Understanding Major Trends impacting Ignition Probability and Wildfire Consequence

Describe how the utility assesses wildfire risk in terms of ignition probability and estimated wildfire consequence, including use of Multi-Attribute Risk Score (MARS) and Multi-Attribute Value Function (MAVF) as in the Safety Model and Assessment Proceeding (S-MAP)[13] and Risk Assessment Mitigation Phase (RAMP), highlighting changes since the 2020 WMP and 2021 Update. Include description of how the utility distinguishes between these risks and the risks to safety and reliability. List and describe each "known local condition" that the utility monitors per GO 95, Rule 31.1, including how the condition is monitored and evaluated.

[13] Updates to S-MAP are currently in deliberation under proceeding R. 20-07-013 – Order Instituting Rulemaking to Further Develop a Risk-based Decision-making Framework for Electric and Gas Utilities.

In addition:

Describe how the utility monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making, including describing any utility-generated Fire Potential Index or other measure (including input variables, equations, the scale or rating system, an explanation of how uncertainties are accounted for, an explanation of how this index is used to inform operational decisions, and an explanation of how trends in index ratings impact medium-term decisions such as maintenance and longer-term decisions such as capital investments, etc.).

Describe how the utility monitors and accounts for the contribution of fuel conditions to ignition probability and estimated wildfire consequence in its decision-making, including describing any proprietary fuel condition index (or other measures tracked), the outputs of said index or other measures, and the methodology used for projecting future fuel conditions. Include discussion of measurements and units for live fuel moisture content, dead fuel moisture content, density of each fuel type, and any other variables tracked. Describe the measures and thresholds the utility uses to determine extreme fuel conditions, including what fuel moisture measurements and threshold values the utility considers "extreme" and its strategy for how fuel conditions inform operational decision-making.

Assessment of Wildfire Risk in terms of Ignition Probability and Estimated Wildfire Consequence

BVES is not required by the California Public Utilities Commission (CPUC) to develop either a Multi-Attribute Value Function (MAVF) or Multi-Attribute Risk Score (MARS) framework for Risk Assessment Mitigation Phase (RAMP) filings; however, BVES maintains a risk assessment toolkit to help identify risk drivers and better understand the potential consequences of wildfire threat while gauging the success of mitigation initiatives. Additionally, BVES is tracking current proceeding activities under R. 20-07-013, for which Safety Model and Assessment Proceeding (S-MAP) enhancements continue to be developed.

Currently, BVES evaluates enterprise risk using its Fire Safety Circuit Matrix and Risk Register to prioritize wildfire risk. BVES has also modeled risk due to safety, reliability, and loss of energy supply threshold risk to account for differentiating threats within the service area. These models are discussed in detail within **Section 4.5.1**. BVES also uses a Risk-Based Decision-Making Framework in accordance with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D. 19-04-020 of April 25, 2019. On May 14, 2020, BVES filed Advice Letter (AL) 388-E, transmitting a Risk Spending Accountability Report (RSAR) pursuant to D. 19-08-027 and D.19-04-020, which was approved by the CPUC on October 12, 2020.[14] On March 30, 2022, BVES filed an AL 440-E RSAR for 2021 transmitting a RSAR pursuant to D. 19-08-027 and D. 19-04-020. BVES is currently working with the CPUC for approval.

Additionally, BVES enhanced its ignition risk mapping methodology with the completion of several ignition probability models in 2021. The model results aim to better predict, quantify, and measure risk drivers across all initiatives under high-risk and climate change related metrological forecasts, which will enhance weather monitoring activities on a routine basis.

By the end of June 2022, BVES plans to contract with Technosylva to support the Risk Mapping Program to further improve situational awareness. Better understanding of the risk environment should improve BVES's resource allocation. This effort will leverage Technosylva's Wildfire Analyst Enterprise (WFA-E) software capabilities and solutions implemented across California for other electric utility companies. Engaging with Technosylva will provide BVES software applications and analysis to generate the following:

[14] On October 12, 2020, the Energy Division under the CPUC reviewed BVES's report and found that the utility complied with D. 19-08-27 and D.19-04-020.

Through use of WFA-E FireSim, provision of on-demand, real time wildfire behavior modeling, predictive spread conditions, and derivation of potential impacts analysis

Ability to conduct simulations on-demand, to reflect changing conditions or local data observations, including proactive "what if" scenarios

Weather and wildfire risk forecasting for customer assets and the service territory using daily weather prediction integration to support PSPS activation calls and response operations

Asset risk analysis using historical weather climatology to support WMP development and mitigation planning

Enterprise Risk Mitigation Strategy

BVES maintains a risk mitigation strategy to prioritize the most cost and operationally effective strategies for risk reduction. The methodology identifies inherent risk, existing controls, residual risk, and future mitigation efforts after determining the likelihood and impact of wildfire risk in the service territory. This is the primary risk evaluation tool utilized to prioritize and plan for WMP initiatives. BVES's Risk-Based Decision-Making Framework is consistent with other SMJUs based on direction from the Commission. **Figure 4.2-1** provides an overview of the steps.

Figure 4.2-1: BVES Risk-Based Decision-Making Framework

The BVES Risk Register Model evaluates the enterprise risk reduction relative to the cost of the mitigation using a RSE analysis. This analysis focuses on a review of ongoing and potential new projects to mitigate the three primary wildfire risk events:

- Wildfire Public Safety
- Wildfire – Significant Loss of Property
- Loss of Energy Supplies

The enterprise risk evaluation considers a reasonable worst-case scenario for the three primary wildfire risk events. For each primary risk event, BVES determined the frequency of occurrence and impact scores for each of the weighted risk scoring inputs listed below:

- System reliability impacts
- Regulatory compliance and legal implications
- Quality of service to customers
- Personal and public safety
- Environmental impacts

The Risk Register Model quantifies mitigation projects and programs by the risk benefit and RSE. This allows BVES to better evaluate projects in terms of risk reduction and select the most cost-effective and efficient project among alternatives. BVES utilizes a 7x7 log score model matrix to determine an impact risk score for each weighted scoring input in the Risk Register. The weighted impact scores are accumulated to arrive at a total risk score. The risk scoring inputs, and total risk score form the basis of evaluation for each identified wildfire mitigation activity or initiative. Mitigation activities can be applied to a single or multiple risk events. BVES then calculates the risk reduction or risk benefit for each scoring input to arrive at a weighted mitigated risk score. The risk benefit for each combination of mitigation activity and risk event is determined by subtracting the mitigated risk score from the total risk score. BVES also defines an equivalent annual cost for each mitigation activity. Finally, the risk register determines the RSE by dividing the risk benefit by the equivalent annual cost.

The analysis performed for the 2022 WMP produced the two figures below. Figure 4.2-2: Risk Reduction and Efficiencies of Mitigation Initiatives**Figure 4.2-2** provides a representation of the RSE of mitigation initiatives for the primary drivers of ignition risk. As seen in **Figure 4.2-3Figure** , several of these critical hardening programs are capital intensive and generally yield lower RSE values. These programs are prudent, and are critical to hardening BVES's system, and represent proactive measures to mitigate wildfire risks that have been widely adopted across California and elsewhere.

Figure 4.2-2: Risk Reduction and Efficiencies of Mitigation Initiatives

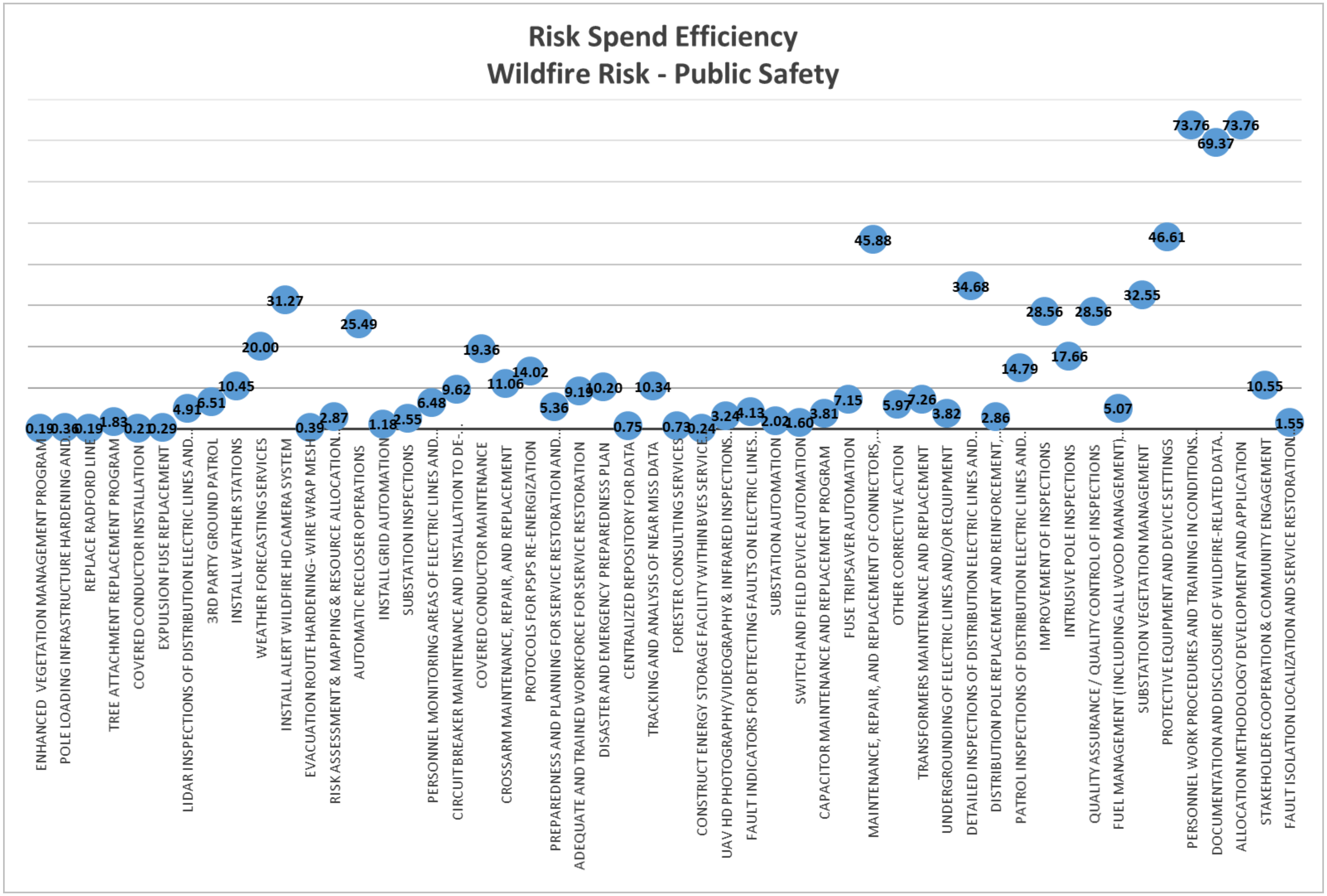
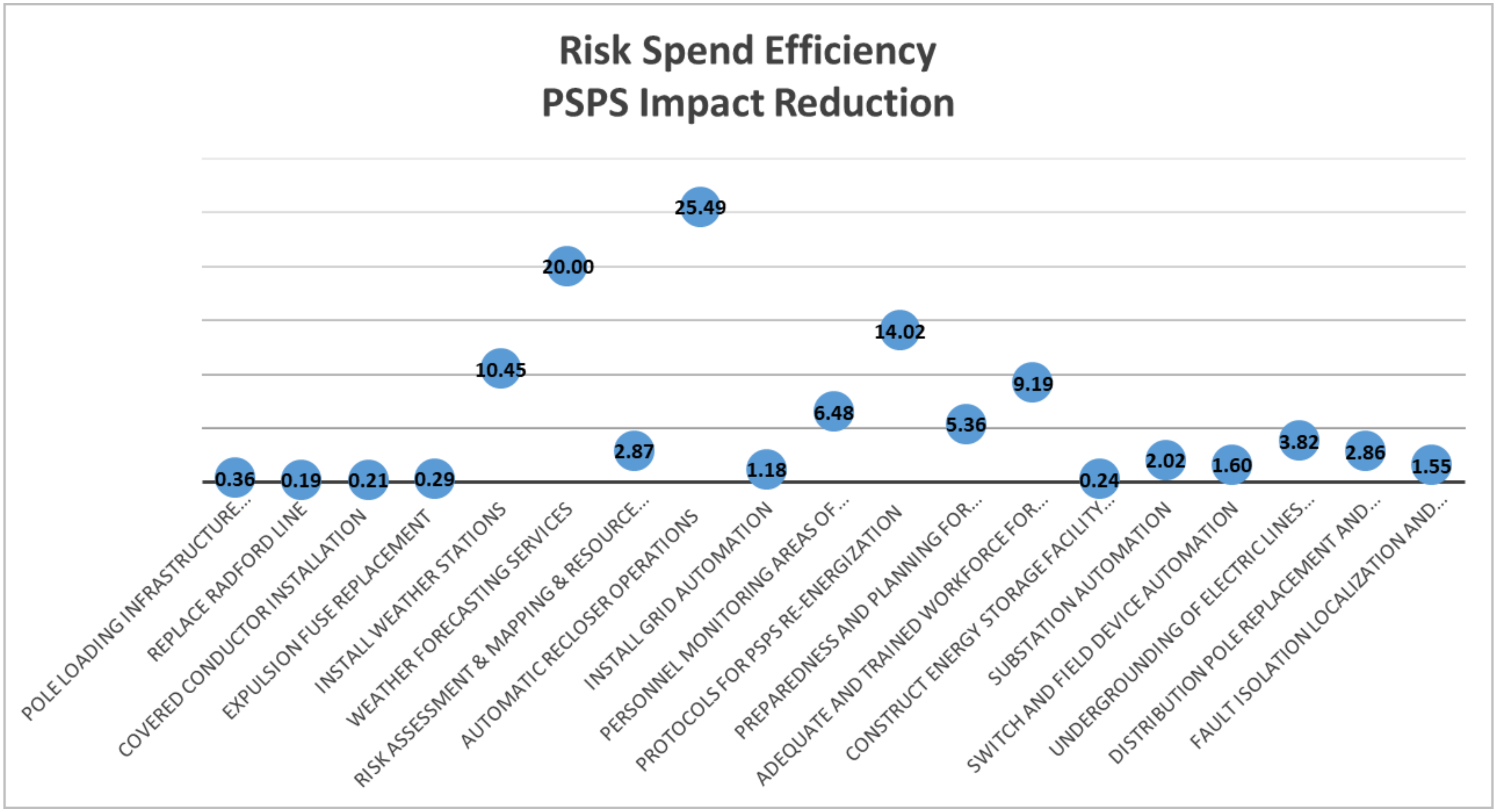


Figure 4.2-3: Risk Spend Ratio / Risk Reduction for PSPS Mitigations



Fire Safety Circuit Matrix

The Fire Safety Circuit Matrix aims to characterize all BVES distribution circuits in groups of High, Moderate, and Low wildfire risk and then prioritize the circuits within each wildfire risk group. To meet this objective, BVES developed a balanced scorecard approach with the use of a Fire Safety Circuit Matrix (a screenshot of some elements that go into the Fire Matrix is demonstrated below in Error! Reference source not found.**)**. The matrix data inputs include, *inter alia*, the number of customers, wood poles, bare wire overhead circuit miles, tree attachments, and remaining expulsion fuses, which are then compiled and weighted to calculate the wildfire risk mitigation score. Currently, seven circuits are rated High Risk, 12 circuits are rated Moderate Risk, and seven circuits are rated Low Risk.

In addition to evaluating the risk reduction and RSE, BVES must account for the timing and proper sequencing of the various wildfire mitigation initiatives. For example, while the Situational Awareness Enhancement Project (establishing a distribution management center) offers a relatively high RSE, it cannot be fully completed until various grid automation initiatives are near completion in 2025.

BVES uses the Fire Safety Circuit Matrix as a “living document” as mitigations are implemented. BVES re-evaluates the mitigations, Wildfire Risk Group, Priority, and Mitigation Weight at least every six months. Additionally, the Fire Safety Circuit Matrix is used to gauge progress and set 3- and 10-year targets for the reduction of the wildfire mitigation score and associated wildfire ignition risk reduction.

Table 4.2-1 Evaluation of Higher Fire-Threat Areas

Circuit	Wildfire Risk Group	Overall Risk Weighting	Risk Ranking	Voltage (kV)	High Fire Threat District Tier	Vegetation Density	Wind Intensity	# of Customers	# of Wood Poles	# of Fire Resistant Composite Poles	# of LWS Poles	# of Ductile Iron Poles	Bare Wire OH Circuit Miles	Covered Conductor OH Circuit Miles	UG Circuit Miles
Radford	31215	0.3441	1	34.5	3	High	High	3482	89	0	0	0	2.82	0	0.02
Baldwin	7606	0.0839	2	34.5	2	Medium	High	11584	253	0	3	0	8.44	0.5	0.5
Shay	7103	0.0783	3	34.5	2	Medium	High	9521	609	0	1	0	9.27	7.9	0.39
North Shore (Fawnskin)	6721	0.0741	4	4.16	2	High	High	1523	924	0	0	0	15.83	0	8.09
Goldmine	4491	0.0495	5	4.16	2	Medium	High	1984	601	0	0	0	13.2	0	5.26
Holcomb (Bear City)	4205	0.0464	6	4.16	2	Medium	High	1587	615	0	0	0	13.25	0	0.85
Clubview	3655	0.0403	7	4.16	2	High	Medium	1698	511	0	0	0	10.18	0	0.27
Paradise	2894	0.0319	8	4.16	2	Medium	High	1895	549	0	0	0	9.17	0.68	2
Sunset	2533	0.0279	9	4.16	2	High	Medium	1918	505	0	0	0	8.38	2.29	0.5
Pioneer (Palomino)	2426	0.0267	10	4.16	2	Medium	High	537	602	0	0	0	11.22	5.17	2.95
Castle Glen (Division)	2365	0.0261	11	4.16	2	Medium	High	1188	343	8	0	0	6.74	0.19	3.68
Sunrise (Maple)	2217	0.0244	12	4.16	2	Medium	Medium	1506	348	0	0	0	7.61	0.18	3.86
Erwin Lake	2006	0.0221	13	4.16	2	Medium	High	2533	1060	0	0	0	19.6	2.23	7.41
Eagle	1813	0.0200	14	4.16	2	Medium	Medium	959	323	0	0	0	7.38	0	1.53
Interlaken	1652	0.0182	15	4.16	2	Medium	Medium	880	280	0	0	0	6.45	0	3.55
Lagonita	1576	0.0174	16	4.16	2	Medium	Low	1103	453	0	0	0	7.46	0	1.43
Garstin	1392	0.0153	17	4.16	2	High	Low	1055	277	0	0	0	5.09	0.82	3
Georgia	1280	0.0141	18	4.16	2	Medium	Low	945	349	0	0	0	5.91	0	3.95
Boulder	1230	0.0136	19	4.16	2	Medium	High	2046	1007	0	1	0	17.68	0	1.8
Harnish (Village)	793	0.0087	20	4.16	2	Medium	Low	254	86	0	0	0	1.34	0	1.21
Country Club	709	0.0078	21	4.16	2	Medium	Medium	605	180	0	0	0	3.18	0	0.94
Lift (Summit TOU)	627	0.0069	22	4.16	2	Low	Low	1	1	0	0	0	0.1	0	0
Pump House (Lake)	202	0.0022	23	4.16	2	Low	High	4	22	0	0	0	0.64	0	0.02
Skyline (Summit Res)	0	0.0000	24	4.16	2	Low	Low	0	0	0	0	0	0	0	0
Geronimo (Bear Mtn.)	0	0.0000	24	4.16	2	Low	Low	1	0	0	0	0	0	0	0.03
Fox Farm	0	0.0000	26	4.16	2	Low	Low	35	2	0	0	0	0	0	0.84

Supporting Table 4.2-2 Prioritization of Higher Fire-Threat Areas

Wildfire Risk Groups
High
Moderate
Low

According to the analysis, BVES identified the higher fire-threat areas outlined above, and prioritized activities for this current WMP cycle, to include the following circuits: (1) Radford, (2) Baldwin, (3) Shay, (4) Northshore, (5) Goldmine, (6) Holcomb (Bear City), and (7) Clubview. The model results illustrate a decrease in risk weight of four formerly high-risk circuits, which are now categorized as Moderate risk following successful 2021 WMP implementation activities.

Known Local Condition

With relation to (General Order) GO 95 Rule 31.1, BVES adheres to requirements listed for its design, construction, and maintenance activities within a safe and prudent manner. In some instances, BVES exceeds GO 95 standards such as with vegetation right-of-way (ROW) management utilizing an internal company standard of 72-inch minimum radial clearance specification. With respects to operating its system, BVES monitors meteorological conditions through its situational awareness program, including the use of live data feeds from its own weather stations and visual feeds through the ALERTWildfire network of high-definition (HD) cameras.

BVES's service area is entirely above 3,000 feet requiring all construction to conform to the "heavy" loading standards of GO 95. The wilderness environment with heavily treed terrain makes the territory vulnerable to potential ignition risk. Per GO 95 21.2 and D. 17-12-024 the entire service area is within the HFTD Tiers 2 and 3, requiring BVES to manage its assets with an understanding of elevated hazards for ignition risk. This includes high wind activity, excessive fuel loading, and lower humidity during the summer months. BVES's service territory also experiences heavy winter loading. BVES maintains and operates its equipment with an abundance of caution due to the seasonal conditions, which may impact delivery of power. While BVES's service territory has not experienced a recorded utility-ignition event in recent history, field workers assume variable risks when engaging in line maintenance and construction. In accordance with GO 166 Standard 1.E, BVES performs activities with safety as a principal focus as part of its Fire Prevention Plan and company standards.

Monitoring Weather and Fuel Conditions and Associated Operational Decision Making

2021 Ignition Risk Probability and Consequence Mapping Project

In 2021, BVES developed risk mapping analysis tools, which present weather and climatological-based ignition probability and wildfire consequence under present and likely future conditions. BVES does not maintain a generated Fire Potential Index at this time. However, the contribution of the ignition risk and consequence mapping project provided useful insight into simulations of fire threat given a range of inputs and climatology. The modeling exercise, along with additional mapping and modeling to be performed in 2022, will influence future planning as current initiatives are carried out. The models and maps were finalized in late 2021, providing an initial screening into areas of greatest concern beyond the HFTD and WUI designations. In the future these maps will contribute to navigating decision-making along with existing risk modeling tools maintained by BVES.

The mapping effort responded to the need for a wildfire risk/consequence analysis across the service territory. This included a map of historical utility-caused fire ignition data within California to quantify ignition probability as a function of local environmental variables. Fire modeling methodology were used to quantify consequences of ignitions in proximity to overhead electrical lines. The outputs produced a series of maps under historical, present (2021), and long-term climate change impact (2050) conditions.

To facilitate this work, BVES hired REAX Engineering to develop an empirical model with foundational power line ignition rate (in the units of ignitions / line miles / hour) utilizing CPUC fire incident data[15] and gridded meteorological data. These inputs assisted in quantifying power line ignition rates as a function of wind gust speed and fuel loading ignition probability. This function is analogous to the National Fire Danger Rating System (NFDRS), which BVES has historically monitored for awareness of environmental and climatological conditions. This modeling demonstrated fuel condition ignition probability as a function of fine fuel moisture content (relative to humidity and temperature) and climate. Additionally, weather conditions present at the time and location of each of the fire incident data matrices contributed to the assessment to determine the Real Time Mesoscale Analysis (RTMA) dataset, conveying hourly estimates of sensible weather variables on a regional boundary of 2.5 kilometers for the United States.

To convert these inputs into the desired unit for ignition rate (ignition / line miles / hour), the steps included calculating the fire incident data utilizing the number of overhead power line miles in each RTMA grid cell, establishing discrete wind gust/ignition probability groupings attributed to the line mile-hours of affected conductors, and incorporating the number of reportable fire incidents to determine the number of ignitions per year per utility. While limitations to the dataset exist, the public nature and data attributes conform to the ignition probability modeling methodology. Notably, granularity in system operations and distinct vegetation canopies were omitted in this analysis.

Current climatology and weather data is incorporated in the National Oceanic and Atmospheric Administration (NOAA) National Centers for Environmental Prediction (NCEP) RTMA. To predict 2050 conditions, climatology and weather conditions from the Weather Research and Forecasting (WRF) were derived from global climate models from the 6th Coupled Model Intercomparison Project enabling a view of hourly, gridded fields of temperature, relative humidity, wind speed, and its direction over a 3-kilometer resolution. A temporal block from years 2046-2055 was selected for the analysis. Fuel and topography were derived from publicly available California fuel conditions datasets and were carried out to 2050. Notable landmarks and structures were also incorporated along with BVES's electrical assets and overall system.

Modeling proceeded with an hourly look into the climatology, which was produced using downscaled WRF 2050 projections and the RTMA in the current 2021 conditions. It is noted that future climate change impacts are uncertain, and that the model provides use of public datasets, which infer increasing conditions based on current climatology. Spatial variation in probability of ignition was calculated using the conductor length per unit area with ignition rate modeled using interpolation. This provides the ignition per unit area per unit time. Fire spread was modeled, unsuppressed, for a 48-hour window to observe vegetation burn and structural damage. Those structures and impacted regions were recorded.

<u>Baseline Weather and Fuel Conditional Awareness</u>

BVES's forecasting framework for fire prevention measures has historically relied on the results of the NFDRS monitoring platform and contract meteorologist evaluation of the local forecast and conditions. These services provide a wildfire risk forecast based on weather, fuel build up, and fuel dryness among other factors, and results in the designation of high-risk days. The NFDRS is generally updated three to five times per day. The meteorologist integrates the NFDRS with the detailed local forecast specific to BVES's service area and develops a risk rating as indicated below in **Table 4.2-3**.

[15] Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric must provide annual fire incident data to the CPUC for public use through the "Fire Incident Data Collection Plan" under D.14-02-015 issued on February 10, 2014.

The Field Operations Supervisor monitors the fire risk designated by the meteorologist, the NFDRS fire danger forecast, and indications from installed weather stations, which are equipped with alarms based on wind speed. This data is then used to direct the proper operational pre-planned response. As indicated in **Table 4.2-3** below, “Brown,” “Orange,” and “Red” are considered elevated fire threat conditions that require the BVES system to be configured for fire prevention taking precedence over reliability concerns.

Table 4.2-3: Pre-Planned Operational Direction Based on Wildfire Risk Forecast

Operations Pre-Planned Action	Green	Yellow	Brown	Orange	Red
Auto-Reclosers and Protective Switches with Reclosing Capability[16]	Automatic	Automatic	Manual (Non-Automatic)		
Patrol following circuit or feeder outage[17]	No	No	Yes		
Fuse TripSavers	Automatic	Automatic	Manual (Non-Automatic)		
Radford Line Use[18]	May be energized	May be energized	De-energize[19]	De-energize	De-energize
Deploy Wildfire Risk Team(s) to “high risk” areas	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Forward to Field Operations updated list of medical baseline customers and impacts access and functional needs population	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Activate Emergency Operations Center	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Prepare Bear Valley Power Plant for sustained operations.	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Conduct switching operations to minimize impact of potential PSPS activity	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Activate first responder, local government and agency, customer and community, and stakeholders PSPS plan	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Activate Community Resource Centers	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 mph or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Public Safety Power Shutoff	No	No	Yes, if actual sustained wind or 3-second wind gusts exceed 55 mph.[20]		

[16] During the non-winter months, certain devices identified by the Field Operations Supervisor and approved by the Utility Manager will remain in Manual (Non-Automatic) for the entire period regardless of the wildfire risk.

[17] During the non-winter months, when an Auto-Recloser, Switch, or Fuse TripSaver placed in “Manual” due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is “Green” or “Yellow,” the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk to causing fire.

[18] Normally only energized during winter period. If the Radford Line must be de-energized during winter period due to high-risk conditions, and load is beyond the capability of the Lucerne supply lines plus the BVPP (Bear Valley Power Plant) capacity, then BVES will reduce interruptible customer load as needed.

[19] May be energized if forecasted and actual sustained wind and wind gust conditions are less than 40 mph and the Radford Line is required to meet load demand or the support load due to loss of other power sources or due to planned maintenance when the benefits of the maintenance will reduce the ongoing risk of wildfire. In all of these cases, approval of the Utility Manger is required to energize the Radford Line and will inform the President.

[20] The Utility Manager may initiate PSPS, if in his or her expert judgement, the actual conditions in the field pose a significant safety risk to the public.

Significant Fire Potential Risk is one of many factors BVES monitors to determine on-going maintenance and inspection wildfire mitigation initiatives and to make longer-term decisions regarding capital investments. Changes in Fire Potential Risk are among the factors considered for adjusting wildfire mitigation initiatives and long-term capital investment decisions. Because BVES identifies its risk mitigation strategies based on its list of potential risk events, the WMP aligns closely with its risk-based decision-making framework.

Table 4.2-4 below details how the WMP accounts for identified risks. Each mitigation measure may span several different categories and help mitigate multiple risks. This table's mitigation measures remain current within the 2022 WMP planning outlook.

Table 4.2-4: Risk & Risk Mitigation Mapping

Risk Event	Mitigation Measures
Design & Construction	
Line Attached to Fallen Tree	• Tree Attachment Replacement Program • Vegetation Management Program
Ignition Caused by Equipment/Infrastructure Settings	• Fusing Upgrades (the fuse upgrade program was completed in 2021) • Cover bare lines, prioritizing high-risk areas to prevent ignition • Underground high-risk overhead lines, where appropriate • Enclose substations and related infrastructure • Strengthen poles through Pole Loading Assessment & Remediation and Covered Wire initiatives
Inspection & Maintenance	
Pole Failures	• Pole Loading Assessment & Remediation
Downed Wire	• Automation of grid equipment • Covered Wire initiative • Vegetation Management Program (removal of hazard trees & enhanced clearances) • Tree Attachment Replacement Program • Implement Down Wire Detection Relay Installment Program • Increased inspections (ground patrols and unmanned aerial vehicle (UAV) Thermography & HD Photography/Videography)
Aging Infrastructure	• Pole Loading Assessment & Remediation Program • Electrical Preventative Maintenance Program • Upgrade Program for Substations • Increased on-ground inspections • LiDAR inspections • UAV Thermography & HD Photography/Videography
Vegetation in Proximity to Infrastructure	• Increased on-ground inspections • LiDAR inspections • Vegetation Management Program • Covered wire program • Forester Program
Quickly Changing Environmental Conditions Due to Climate Change	• Increased on-ground inspections • Weather consultant services • Realtime weather station monitoring in SCADA • Expanded use of HD cameras to monitor remote areas with stakeholder engagement • UAV Thermography & HD Photography/Videography • Improved near real-time risk mapping and assessment (Technosylva Applications)
Operational Practices	
Unclear Protocols & Procedures During High-Risk Conditions	• Continue to implement and update protocols and procedures on an as-needed basis

Risk Event	Mitigation Measures
Situational & Conditional Awareness	
Inability to Visualize Equipment in Hard-to-Patrol Areas	• Increased on-ground inspections • Expanded use of HD cameras to monitor remote areas with stakeholder engagement • LiDAR inspections • Implement UAV inspection program • Automation of grid equipment
Imprecise Weather Forecasting	• Consultant meteorologist to analyze weather data • Monitor publicly available weather data in the area • Monitor BVES-owned weather stations • Improved near real-time risk mapping and assessment (Technosylva Applications)
Response & Recovery	
Fatality caused by wildfire / emergency	• Vegetation management program • Pole Loading Assessment & Remediation Program • Fusing replacement program (fully executed) • Covered wire program • Tree Attachment Replacement Program •
Sustained outages affecting health	• Vegetation Management Program • Pole Loading Assessment & Remediation Program • Electrical Preventative Maintenance Program • Automation of grid equipment • Covered wire program

4.2.1 Service Territory Fire Threat Evaluation and Ignition Risk Trends

Present a map of the highest risk areas identified within the current High Fire Threat District (HFTD) tiers of the utility's service territory as a figure in the WMP. Discuss fire threat evaluation of the service territory to determine whether a modification to the HFTD is warranted (i.e., expansion beyond existing Tier 2 and Tier 3 areas). If the utility believes there are areas in its service territory that are not currently included in the HFTD but require prioritization for mitigation efforts, then the utility is required to provide a process outlining the formal steps necessary to have those areas considered for recognition in the CPUC- defined HFTD.[21] Include a discussion of any fire threat assessment of its service territory performed by the electrical corporation, highlighting any changes since prior WMP submissions. In the event that the utility's assessment determines the fire threat rating for any part of its service territory is insufficient (i.e., the actual fire threat is greater than what is indicated by the CPUC's Fire Threat Map and High Fire Threat District designations), the utility is required to identify those areas for potential HFTD modification, based on the new information or environmental changes, showing the differences on a map in the WMP. To the extent this identification relies upon a meteorological or climatological study, a thorough explanation and copy of the study must be included as an Appendix to the WMP.

List, describe, and map geospatially (where geospatial mapping is applicable) any macro trends impacting ignition probability and estimated wildfire consequence within utility service territory, highlighting any changes since the 2021 WMP Update:

Change in ignition probability and estimated wildfire consequence due to climate change

[21] As there is no formal or standard process for modifying the HFTD maps defined by the CPUC, Utilities may utilize a similar approach adopted by SCE during the 2019 WMP review process described in D.19-05-038, pg. 53. For this process, in August 2019 SCE submitted a petition to modify D.17-12-024 to recognize SCE-identified HFRA as HFTD Tier 2 areas.

Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles

Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture

Population changes (including Access and Functional Needs population) that could be impacted by utility ignition

Population changes in HFTD that could be impacted by utility ignition

Population changes in WUI that could be impacted by utility ignition

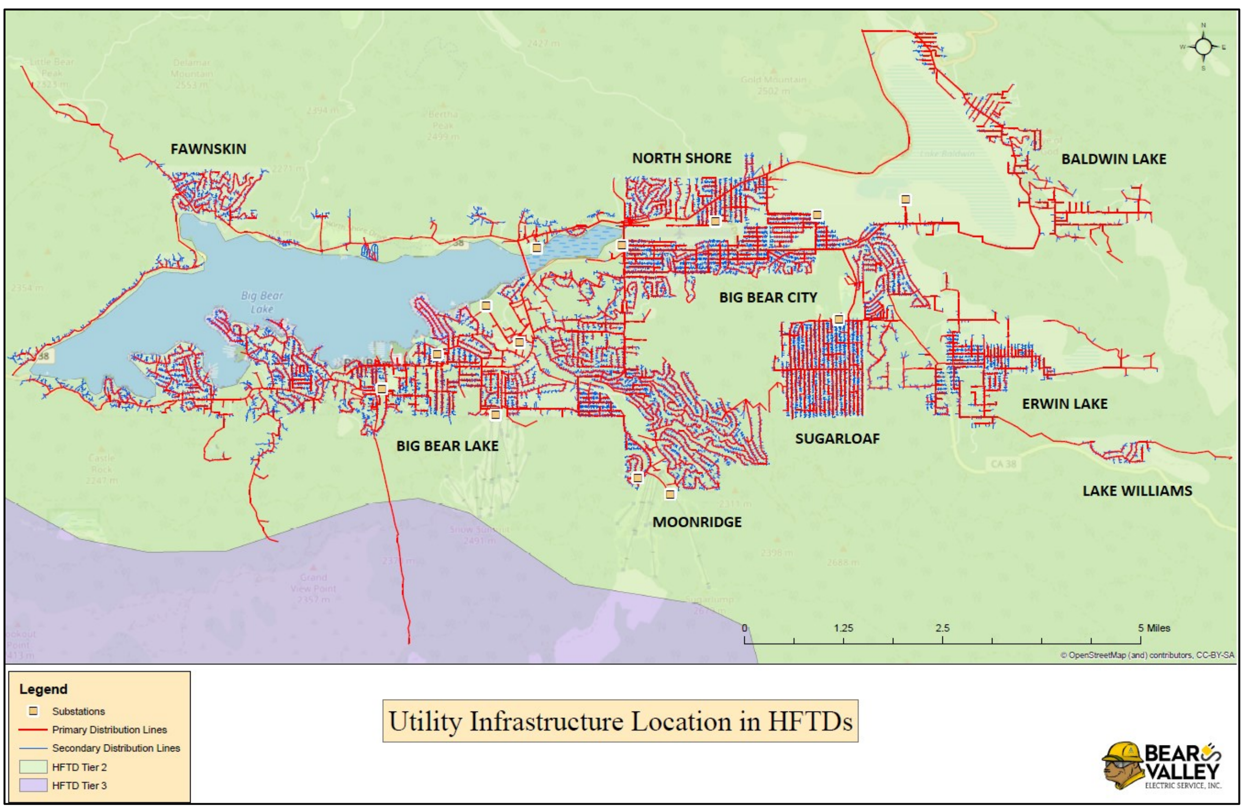
Utility infrastructure location in HFTD vs non-HFTD

Utility infrastructure location in urban vs rural vs highly rural areas

Identified Wildfire Risk Areas

Several wildfire risk assessment designations have been issued from various state and federal organizations seeking to establish an understanding of wildfire risk tiers. These organizations and agencies include the CPUC, the California Department of Forestry and Fire Protection (CAL FIRE), and the US Department of Agriculture (USDA). Each designation provides a different perspective of potential fire danger. For example, the USDA's NFDRS assesses fire-threats at the county-level based on weather, while CAL FIRE includes four fire-hazard severity zones based on various factors. **Figure 4.2-4** shows the CPUC designated fire hazard zone tiers within BVES's service territory.

Figure 4.2-4: BVES CPUC Designated Tier 2 and Tier 3 HFTD



Evaluation of BVES's Service Area HFTD Designations

BVES does not find a need to adjust the HFTD designations beyond what exists for Tier 2 and 3. BVES operates with the inherent risk factors present in the service area's dry, mountainous terrain. Consequently, BVES took an active role in the CPUC's HFTD map creation and approval process. BVES considers the current HFTD designations in the BVES service territory to be appropriate due to the following factors: (1) the entirety of BVES service territory is located within Tier 2 and Tier 3, (2) the lengths to which BVES is undertaking to prevent wildfire ignition and spread, and (3) there are no significantly different risk factors between the time of creation of the CPUC map and now.

Because the entire service territory is within HFTD Tier 2 and a small portion of the Radford line in Tier 3, BVES identified areas of increased concern of fire potential for additional monitoring, initiatives, and assessment. Specifically, BVES established "higher" risk areas within the Tier 2 designation. These areas exhibit more fire risk due to increased vegetation, bark beetle mortality, exposed lines, or areas where a wildfire would be particularly destructive such as those with high customer densities. Additionally, BVES classifies high risk areas as those that have high vegetation density and high winds. Vegetation density is based on SME evaluation of the vegetation around the circuit. Low density is less than 10 trees in the right of way on average per span. BVES has engaged a contractor to improve BVES GIS capabilities including digitizing a record of vegetation management work and more precise accounting of vegetation density and at-risk species. This work continues into 2022. With the addition of the ignition probability and consequence mapping project, BVES gained additional insight into circuits of greatest risk. The determination aligns with the results of the Fire Safety Circuit Matrix findings, which indicates that BVES effectively prioritized the highest risk circuits for mitigation deployments. BVES summarized the inputs, limitations, non-confidential modeling approach, and outcomes above in **Section 4.2** and explained in further detail in **Section 4.5**.

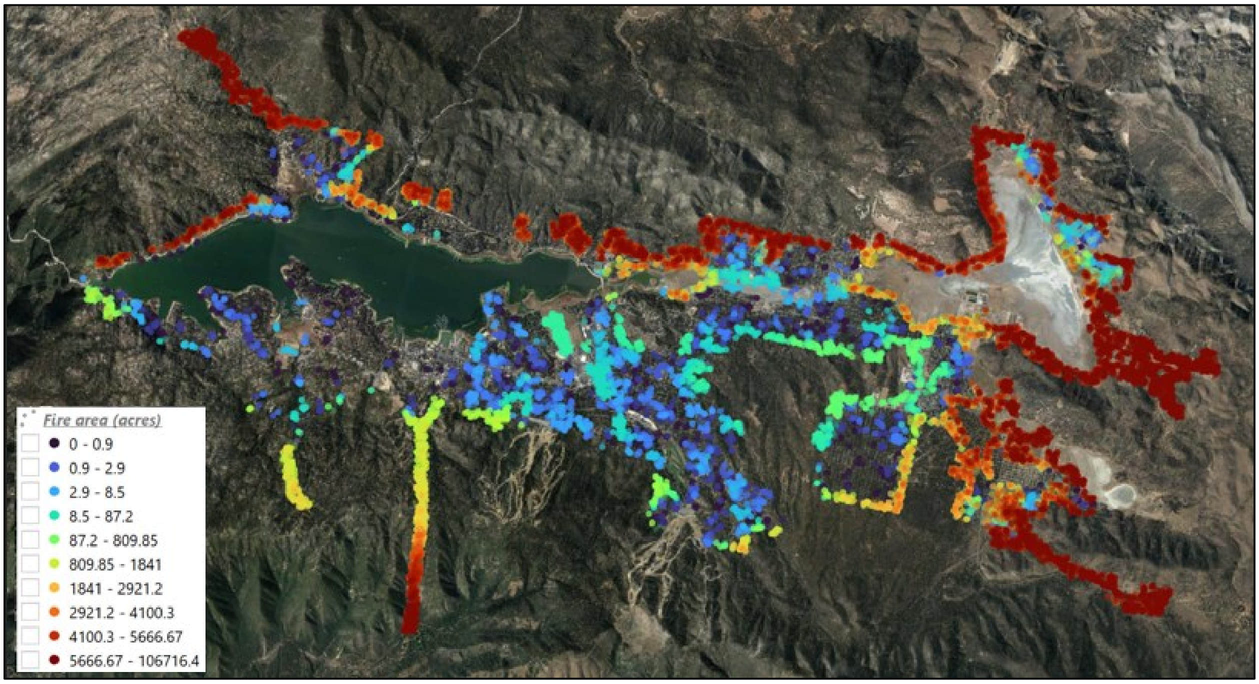
Macro Trends Remain Consistent from 2021 to 2022

BVES does not have any unique macro trends to report related to ignition probability at this time. BVES serves a mountainous resort community with a part-time and permanent resident mix with minimal population changes forecasted over the planning horizon. BVES's Risk-Based Decision-Making Framework is in accordance with the safety model approach for SMJU provided in CPUC D. 19-04-020 on April 25, 2019. With the anticipation of additional risk modeling consultancy through Technosylva, beginning in 2022, BVES will consider any previously unaccounted macro trends to influence high-risk boundary designations within its service territory.

1. Change in ignition probability and estimated wildfire consequence due to climate change

BVES has not historically had reportable or non-reportable utility-involved ignitions, or catastrophic wildfires. However, climate change would, over time, increase the risk of both ignition and wildfire consequence if all else were equal. BVES believes its wildfire mitigation efforts and grid hardening will reduce any upticks in ignition probability. This was analyzed as part of the ignition risk and consequence mapping project, which concluded in 2021. The input data included current (from 2011 to 2021) and future (2050) climate conditions using a downscaled global climate model developed by the UCLA's Department of Atmospheric and Oceanic Sciences. This model was specifically used to predict wildfires and spread and to quantify differences in ignition and spread between 2021 and 2050 conditions.

Figure 4.2-5: Future (2050) Ignition Conditions Impact, Unsuppressed



To counter the likely worsening of wildfire consequences due to climate change, BVES's wildfire mitigation initiatives will help to limit these impacts to BVES and its customers. Moreover, BVES will monitor changes in local climate in the near-term horizon by monitoring temperature and drought; in the medium term by monitoring and analyzing for changing weather patterns and increases in tree mortality and stress; and in the long-term by following scientific understanding of the evolving issue including local impacts. BVES will make risk-informed decisions based on these inputs to maintain the level of safety, reliability, and wildfire preparedness expected by its customers and community stakeholders.

2. Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles

Change in ignition probability due to invasive and at-risk species is not anticipated at this time and has not impacted risk forecasts from 2021 to 2022.

BVES acknowledges the pervasiveness and continued growth of pine beetles and other insect borers across California forests, including in BVES's service territory, is a cause for concern. Infestations by these and other pests increase tree mortality and distressed trees. The increased prevalence of distressed and dead trees affects wildfire behavior by increasing the severity, intensity, and the rate of spread. Though, recent reports from the National Forest Service Library convey that tree species within BVES's service area experience low bark beetle impacts on wildfire behavior and severity.[22] This includes "Low" severity impacts categorized for Jeffrey pine, Sugar pine, Ponderosa pine, and White spruce. Douglas-fir trees do, however, experience a "Moderate" impact to wildfire behavior and severity.[23]

Invasive tree species, such as eucalyptus trees, that are less drought tolerant or less fire resistant, or demonstrate different growth characteristics than native species, can also be problematic and increase

[22] The conducted study focused primarily on the threats and impacts from the mountain pine beetle outbreaks, which is the insect species most intensively monitored for wildfire behavior and consequence severity.

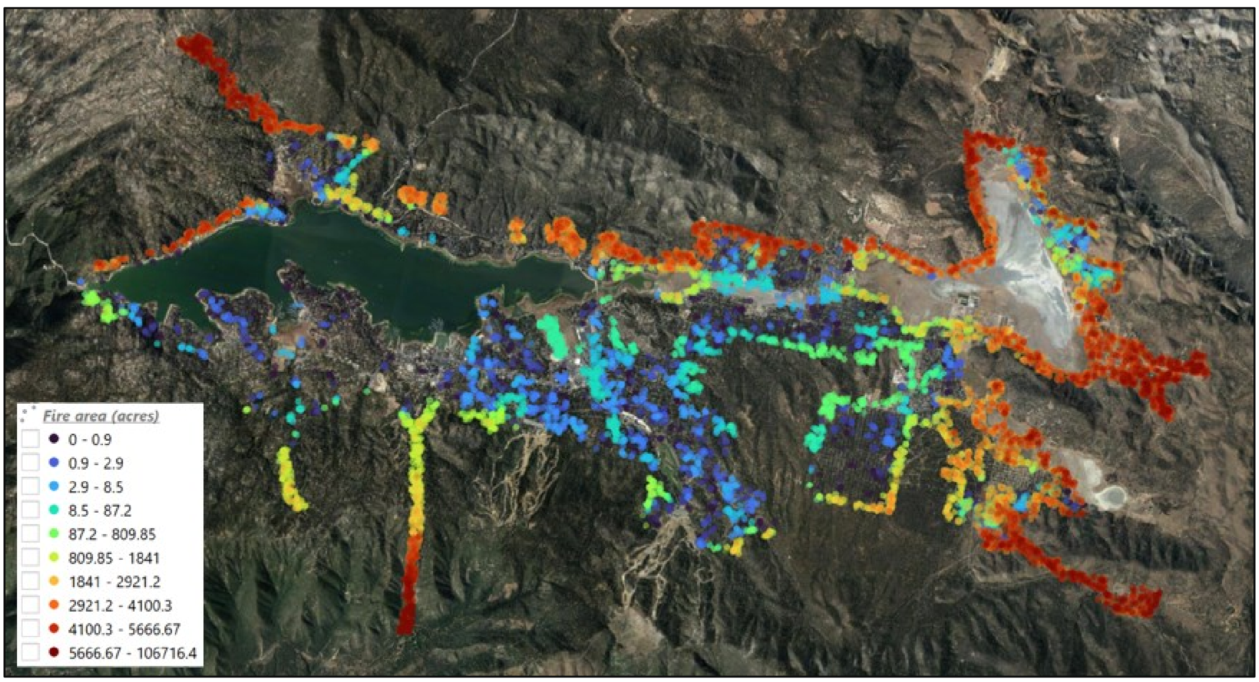
[23] Fettig, Christopher J., et. al., "Bark Beetle and Fire Interactions in Western Coniferous Forests: Research Findings," Wildfire Management Today, Volume 79, Number 1, January 2021. https://www.fs.fed.us/psw/publications/fettig/psw_2021_fettig006.pdf.

fire risk along ROWs and near BVES equipment and facilities. BVES vegetation management operations, performed by tree specialist contractors, take the presence of invasive species and their growth rates into account when performing vegetation management actions. Invasive and at-risk species are tracked by vegetation management contractors along with other tree tracking information. Extra clearance or tree removal is required of flammable or high-growth rate invasive species. BVES engaged a contract forester in 2021 to address these and other vegetation management issues. BVES is also expanding its GIS capabilities to include more vegetation management and tree tracking information.

3. Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture

Increased ignition probability and estimated wildfire consequence in response to changes in fuel density and moisture is not anticipated in the modeling. As stated above, BVES plans to move toward enhancing its risk framework and methodology and its capabilities to assess internally derived quantitative analysis on fire risk. Currently, the utility monitors fuel conditions through public weather and fire risk data monitoring systems as well as through its weather stations and wildland cameras. The current 2021 conditions of wildfire consequence are presented in the image below.

Figure 4.2-6: Current 2021 Conditions of Wildfire Consequence Simulation



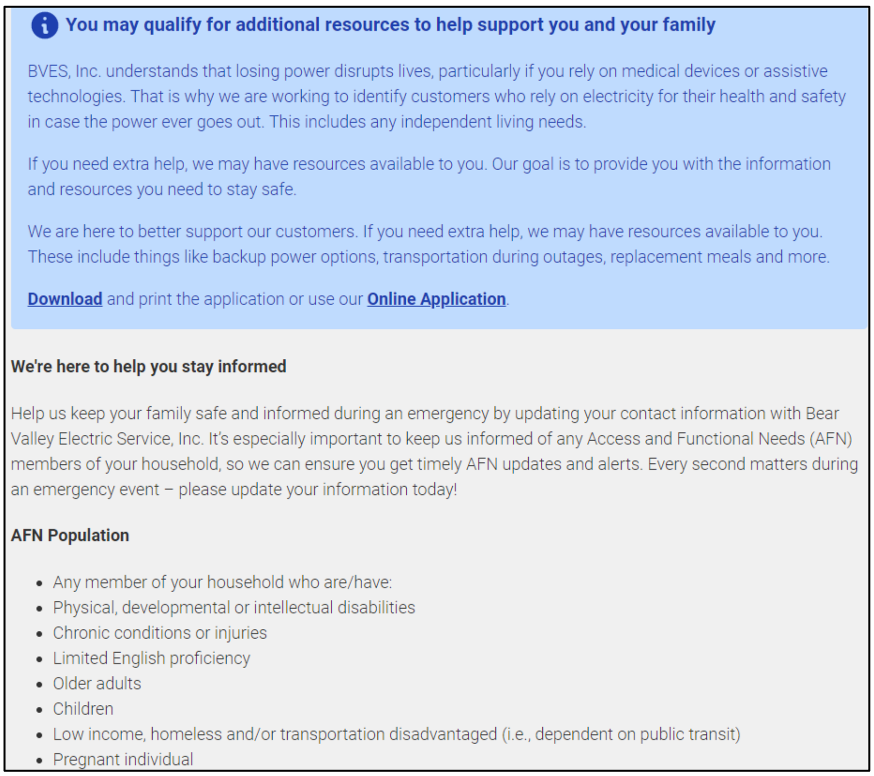
Climate change will likely cause an increase in ignition probability and wildfire consequences as demonstrated in the heat map in **Figure 4.2-6**. High temperatures, persistent drought, and high winds, which may all increase due to climate change, decrease embedded moisture across all fuel classes (1, 10, 100, and 1000-hour fuels) and escalate wildfire risk. This may also raise bark beetle mortality and the relative prevalence of problematic invasive species. Additionally, a lack of fire due to fire suppression efforts has led to increases in fuel density and mixed-aged stands with smaller diameter trees that serve as ladder fuels that can enable crown fires that spread rapidly and are difficult to contain. BVES, by and through its contract forester, vegetation management specialist, and contract meteorologist will closely monitor these conditions. This may cause BVES to re-evaluate its operations during high fire threat days, perhaps even seasonally.

4. Population changes (including Access and Functional Needs population) that could be impacted by utility ignition

BVES is not expecting any significant population fluctuations. While some changes to the seasonality may be underway due to the ongoing populations shift as a result of the COVID-19 pandemic, which accelerated the adoption of remote work, those figures do not yet show much in BVES's service numbers. BVES will continue to monitor its fluctuations in population growth as part of routine energy resource planning strategy and adopt its WMP initiatives accordingly.

The more likely population change will be more year-round residents which may, in relative terms, shift usage patterns from seasonal, leisure driven peaks, to a load curve more in line with traditional year-round communities. Similarly, BVES is continuing to assess self-identified customers that fall within the Access and Functional Needs (AFN) population by direct outreach and accounting for medical baseline or low-income customers.[24] Self-assessment and applications are provided on BVES's website, as shown in the screengrab below.

Figure 4.2-7: BVES AFN Customer Application Portal



You may qualify for additional resources to help support you and your family

BVES, Inc. understands that losing power disrupts lives, particularly if you rely on medical devices or assistive technologies. That is why we are working to identify customers who rely on electricity for their health and safety in case the power ever goes out. This includes any independent living needs.

If you need extra help, we may have resources available to you. Our goal is to provide you with the information and resources you need to stay safe.

We are here to better support our customers. If you need extra help, we may have resources available to you. These include things like backup power options, transportation during outages, replacement meals and more.

Download and print the application or use our **Online Application**.

We're here to help you stay informed

Help us keep your family safe and informed during an emergency by updating your contact information with Bear Valley Electric Service, Inc. It's especially important to keep us informed of any Access and Functional Needs (AFN) members of your household, so we can ensure you get timely AFN updates and alerts. Every second matters during an emergency event – please update your information today!

AFN Population

- Any member of your household who are/have:
- Physical, developmental or intellectual disabilities
- Chronic conditions or injuries
- Limited English proficiency
- Older adults
- Children
- Low income, homeless and/or transportation disadvantaged (i.e., dependent on public transit)
- Pregnant individual

5. Population changes in HFTD that could be impacted by utility ignition

BVES does not anticipate any population changes in the HFTD that could be impacted by utility ignition at this time. Virtually all residents reside in Tier 2 of the service area. BVES has not encountered any reportable utility ignitions. BVES will continue to monitor any fluctuations and report any deviations in anticipated growth into these areas in a future update.

[24] BVES, "Access & Functional Needs," https://www.bvesinc.com/forms/afn-application.

6. Population changes in WUI that could be impacted by utility ignition

The entirety of BVES's service territory is in the WUI. Therefore, any population changes would represent a change in the WUI. As observed across California and elsewhere, an increase of population coincides with an increase in ignition probability. Since BVES does not expect any population changes in its service territory, the WUI population should not change, nor should the utility ignition probability or numbers impacted by utility ignition. BVES will continue to monitor developments in the WUI as BVES is aware that some of the most significant wildfire challenges exist and persist in the WUI and utility operations in such areas must be evaluated for ignition probability and risk reduction measures.

7. Utility infrastructure location in HFTD vs non-HFTD

BVES does not anticipate any changes with utility infrastructure location between HFTD and non-HFTD areas due to nearly all of the utility's service area being located in Tier 2. BVES also has a small portion in Tier 3 overlapping with the Radford line, which was prioritized for hardening efforts and is the location of a weather station in this small portion of the Tier 3 installed in 2021. No future plans exist in Tier 3 regarding utility infrastructure. BVES does not own or operate any infrastructure in non-HFTD areas.

8. Utility infrastructure location in urban vs rural vs highly rural areas

BVES does not anticipate a change in infrastructure locations among urban, rural, and highly rural areas. The utility service territory is a mix of urban and rural areas. These designations represent an update from BVES's previous understanding of the demarcation between urban, rural, and highly rural as it has made progress on its GIS mapping. The majority of utility infrastructure mitigation activities reside in the rural designation.

4.3 Change in Ignition Probability Drivers

Based on the implementation of the above wildfire mitigation initiatives, explain how the utility sees its ignition probability drivers evolving over the 3-year term of the WMP, highlighting any changes since the 2021 WMP Update. Focus on ignition probability and estimated wildfire consequence reduction by ignition probability driver, detailed risk driver, and include a description of how the utility expects to see incidents evolve over the same period, both in total number (of occurrence of a given incident type, whether resulting in an ignition or not) and in likelihood of causing an ignition by type. Outline methodology for determining ignition probability from events, including data used to determine likelihood of ignition probability, such as past ignition events, number of risk events, and description of events (including vegetation and equipment condition).

Service Territory Description & Evolving Three-Year Term Risks

As part of its risk analysis, BVES examines its service territory to identify hazards and potential ignition and PSPS threats unique to its geography. This section provides an overview of the service territory and details the risks BVES factored into its mitigation strategy. BVES's service territory is in the mountain resort community of Big Bear Lake, California, with approximately 24,650 customers in a 32 square-mile service area located in the San Bernardino Mountains of Southern California, 80 miles east of Los Angeles, the region is remote and mountainous.

Figure 4.3-1: BVES Circuit Map (2021)

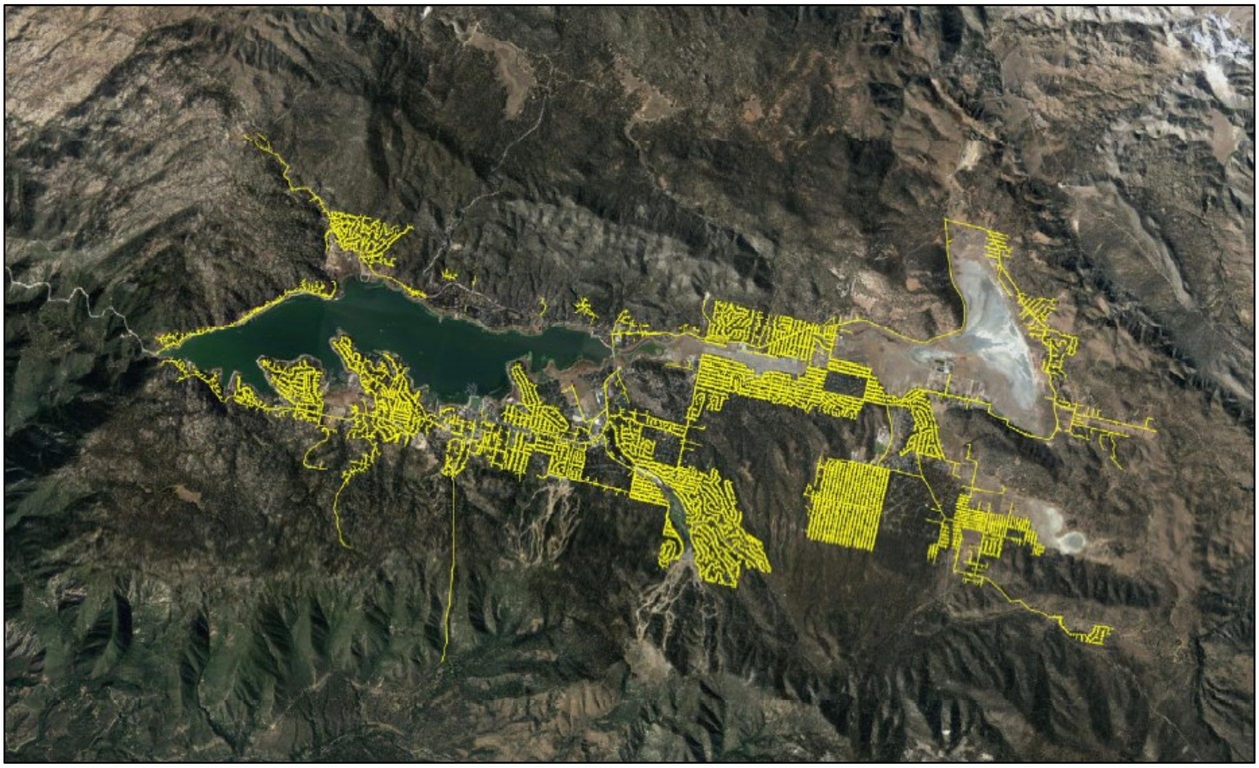
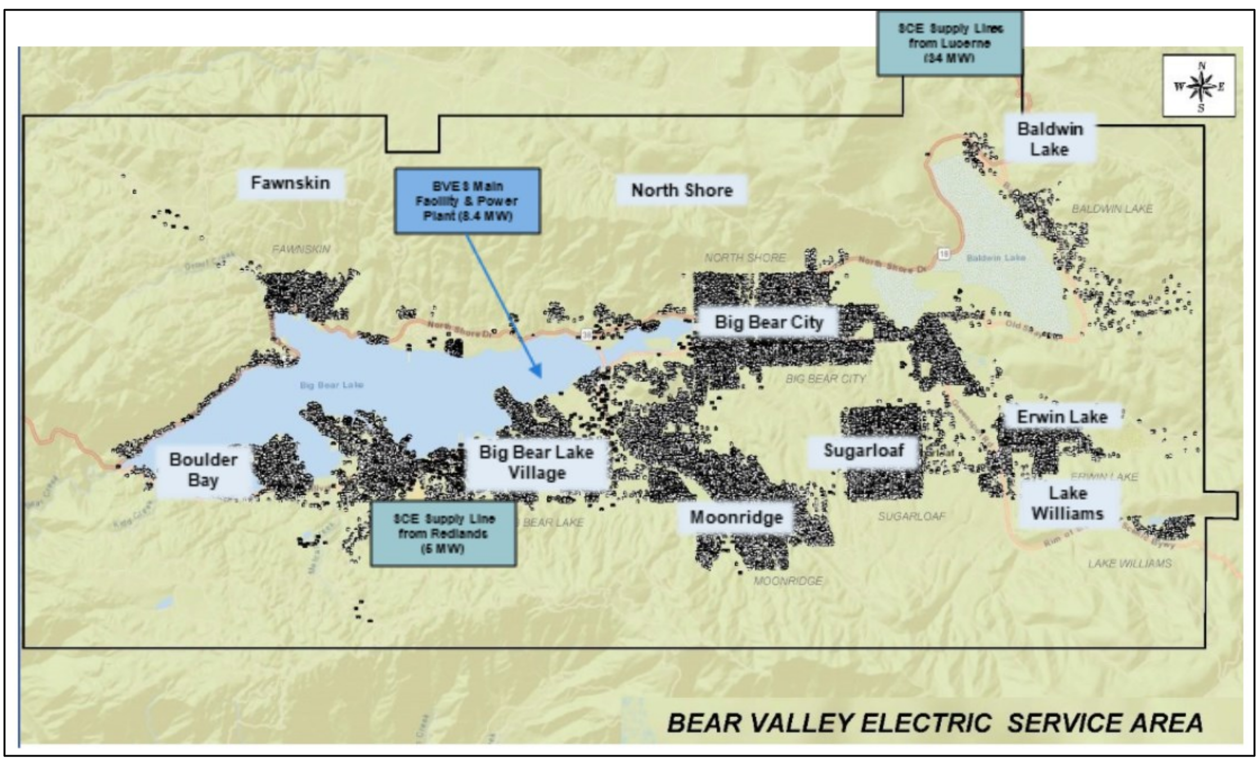


Figure 4.3-2: Map of BVES Service Territory and Key Areas



Given its unique service territory, BVES considers, among other factors, the following when making decisions and implementing plans related to wildfire mitigation: (1) electrical system design and assets, (2) complex jurisdictional structure, (3) local load profile, and (4) geographic location.

Electrical System Design & Assets: BVES owns and operates 87.8 line miles of OH 34.5 kV sub-transmission lines, 2.7 line miles of 34.5 kV UG sub-transmission lines, 488.6 line miles of OH distribution circuit lines, 89.1 line miles of UG distribution circuit lines, 13 substations, and a natural gas-fueled 8.4 megawatt (MW) peaking generation facility.

Jurisdictional Structure: The majority of BVES's service area is under the jurisdictional responsibility of the City of Big Bear Lake, with some unincorporated areas under the responsibility of the County of San Bernardino. The San Bernardino Mountains and forests are managed by the USFS, California Environmental Protection Agency, and the California Department of Fish and Wildlife. This complex and sometimes overlapping jurisdictional structure is a key consideration when developing or implementing any strategic plan, including one related to wildfires.

Local Load Profile: Big Bear Lake is primarily a vacation destination during the winter months. This results in a winter peaking profile that occurs due to increased load from population influx and local snow-making activity in the late evening hours. Throughout the rest of the year, system load returns to normal. Understanding this unique local load profile is a key element of implementing a successful WMP.

Geographic Location: BVES's service area is entirely above the 3,000-foot elevation threshold (which requires heavy loading construction standards) and has a high density of trees in a mostly dry environment. Wind intensity during dry periods is generally not significant (winds are typically no more than 25 mph during dry periods).

BVES regularly monitors these third-party risk assessments and has created procedures and protocols accordingly. **Table 4.3-1** below outlines the various rating systems and BVES's rating in that system.

Table 4.3-1: Wildfire Risk Assessments in BVES Service Territory

Agency and Rating Name	Scope of Rating	BVES Rating
CPUC, Fire-Threat Map Adopted January 19, 2018[25]	Areas or zones where enhanced fire safety regulations in Decision 17-12-024 will apply[26]	High Fire-Threat District; Mostly Tier 2 (elevated risk) with some Tier 3 (extreme risk) areas.
USDA Forest Service, NFDRS[27]	County-level assessment of fire danger for that day or the next day based on fuels, weather, topography, and risks	75.3% of the time "Very Dry" or "Dry"[28]
CAL FIRE, California Fire Hazard Severity Zone Map Update Project[29]	City and County-level assessments of fire "hazard" zones	Very High Fire Hazard Severity Zone

[25] CPUC, CPUC Fire Safety Rulemaking Background, 2018, http://www.cpuc.ca.gov/firethreatmaps/.

[26] CPUC, CPUC Adopts New Fire-Safety Regulations, December 14, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352402.PDF.

[27] USDA Forest Service, National Fire Danger Rating System, https://www.fs.usda.gov/detail/inyo/home/?cid=stelprdb5173311.; BVES Analysis

[28] Based on 2015-2021 available data

[29] CAL FIRE, Wildland Hazard & Building Codes Cities for which CAL FIRE has made recommendations on Very High Fire Hazard Severity Zones (VHFHSZ), http://www.fire.ca.gov/fire_prevention/fire_prevention_wildland_zones_maps_citylist.

In addition to gaining a deeper understanding of its wildfire risks, BVES analyzed its reliability data to prioritize its risks. Tables 7.1 and 7.2 in the QDR provides recent incident data analysis that examines three types of events: (1) bare-line contacts from objects, (2) all types of equipment or facility failures, and (3) wire-to-wire contact, since these types of events may result in wildfires. Vegetation and bare-line contact events are the most frequently occurring events and are mainly caused by weather and third parties. This is due to the dense tree coverage of the mountainous terrain and the susceptibility to heavy winter snowstorms. The risk of fire during these storms is diminished due to the moisture level in surrounding vegetation and on the ground is typically high, reducing the risk of wildfire.

Based on the implementation of its wildfire mitigation initiatives, BVES believes its ignition probability drivers will continue to decline over the three-year term of the WMP. To date, BVES has focused much of its efforts on reducing ignition sources, such as reducing the amount of bare wire present in its service territory. BVES is also implementing measures to reduce the wildfire consequence by increasing situational awareness, hardening overhead facilities along evacuation routes, and increasing coordination with public safety agencies. Using the Fire Safety Circuit Matrix, BVES anticipates risk reduction of its circuits over the next ten years. See the table below.

Table 4.3-2: 10 Year Fire Risk Reduction Outlook

Circuit	Substation	2019 Wildfire Risk Group	2020 Wildfire Risk Group	2021 Wildfire Risk Group	2022 Wildfire Risk Group	2024 Wildfire Risk Group	2032 Wildfire Risk Group
Radford	SCE Feed	30521	30521	31215	522	522	77
Shay	SCE Feed	14230	14230	7103	4053	0	0
Baldwin	SCE Feed	7185	7185	7606	6884	4311	0
Boulder	Village	3351	3351	1230	1141	0	0
North Shore (Fawnskin)	Fawnskin	7518	7518	6721	6721	5218	0
Erwin Lake	Maltby	7401	7401	2006	1379	150	0
Pioneer (Palomino)	Palomino	5706	5706	2426	2426	1214	0
Clubview	Moonridge	3460	3460	3331	2826	1574	0
Goldmine	Moonridge	5559	5559	4491	4491	3623	0
Paradise	Maltby	2754	2754	2894	1646	1303	0
Sunset	Maple	3583	3583	2533	2533	2225	0
Sunrise (Maple)	Maple	2650	2650	2217	2217	2117	0
Holcomb (Bear City)	Bear City	5916	5916	4205	4120	4070	0
Georgia	Pineknot	1919	1919	1280	1280	1280	0
Eagle	Pineknot	2072	2072	1813	1813	1746	67
Harnish (Village)	Village	385	385	793	786	786	312
Garstin	Meadow	2440	2440	1392	1366	1291	0
Lagonita	Village	2023	2023	1576	1539	1539	0
Interlaken	Meadow	3275	3275	1652	1472	1422	0
Castle Glen (Division)	Division	1982	1982	2365	1725	1725	0
Country Club	Division	984	984	709	693	626	0
Fox Farm	Meadow	0	0	0	0	0	0
Pump House (Lake)	Lake	287	287	202	202	202	92
Lift (Summit TOU)	Summit	28	28	627	627	627	622
Skyline (Summit Res)	Summit	0	0	0	0	0	0
Geronimo (Bear Mtn.)	Bear Mtn.	0	0	0	0	0	0
		115230	115230	90386	52464	37571	1170

High
Moderate
Low

As these initiatives are executed, the WMP will continue to evolve in an ongoing effort to reduce wildfire and PSPS risk and BVES anticipates a decline in incidents and ignition probability.

Table 4.3-3 below organizes risk reduction strategies included in the WMP.

Table 4.3-3: List of Wildfire Risks and Risk Score (Priority)

Risk Event	*Total Risk Score*
Design & Construction	
Line Attached to Fallen Tree (includes Tree Attachments)	88,191
Inspection & Maintenance	
Pole Failures	49,702
Downed Wire	114,944
Aging Infrastructure	4,966
Operational Practices	
Violations of Safe Work Practice	35,053
Loss of imported energy supplies due to PSPS event	383,444
Situational & Conditional Awareness	
Inability to Visualize Equipment in Hard-to-Patrol Areas	3,641
Response & Recovery	
Fatality(ies) caused by wildfire / emergency	1,275,706
Significant loss of property caused by wildfire	281,097
Sustained outages affecting health	124,339

4.4 Research Proposals and Findings

Report all utility-sponsored research proposals, findings from ongoing studies and findings from studies completed in 2020 and 2021 relevant to wildfire and Public Safety Power Shutoff (PSPS) mitigations.

BVES has not conducted and is not proposing to conduct any research proposals to identify novel methods of reducing wildfire risk. Due to its small size and limited customer base, BVES will track new and proven techniques, technologies, and methods researched and implemented at other utilities, the national laboratories, in academia, and elsewhere and identify opportunities to conduct pilot programs and implement changes that have proven successful in cost-effectively reducing wildfire risk. BVES has completed several pilot programs (covered conductor hardening and evacuation route hardening) and will continue to investigate enhanced mitigations as they are demonstrated among neighboring utilities.

BVES is open to collaborating on research projects on wildfire mitigation and would support outside organizations such as universities performing research in this area.[30]

4.4.1 Research Proposals

Report proposals for future utility-sponsored studies relevant to wildfire and PSPS mitigation. Organize proposals under the following structure:

[30] For example, BVES provided a letter of support for Department of Civil and Environmental Engineering, University of California – Davis research proposal to the California Energy Commission (CEC) on wildfire risk assessment and mitigation under changing climate conditions (CEC GFO-18-301) in March 2019 and was willing to support the research effort in its service area, as applicable. The proposal did not gain approval.

1. ***Purpose of research*** *– brief summary of context and goals of research*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements*** *- Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table below)*
4. ***Methodology*** *- Methodology for analysis, including list of analyses to perform; section shall include statistical models, equations, etc. behind analyses*
5. ***Timeline*** *- Project timeline and reporting frequency to the Office of Energy Infrastructure Safety*

BVES does not maintain any research proposals or sponsored studies relevant to wildfire and PSPS mitigation at this time.

4.4.2 Research Findings

Report findings from ongoing and completed studies relevant to wildfire and PSPS mitigation. Organize findings reports under the following structure:

1. ***Purpose of research*** *– Brief summary of context and goals of research*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements*** *- Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table above)*
4. ***Methodology*** *- Methodology for analysis, including list of analyses to perform; section shall include statistical models, equations, etc. behind analyses*
5. ***Timeline*** *- Project timeline and reporting frequency to the Office of Energy Infrastructure Safety. Include any changes to timeline since last update*
6. ***Results and discussion*** *– Findings and discussion based on findings, highlighting new results and changes to conclusions since last update*
7. ***Follow-up planned*** *– Follow up research or action planned as a result of the research*

BVES does not maintain any research proposals or sponsored studies relevant to wildfire and PSPS mitigation at this time.

4.5 Model and Metric Calculation Methodologies

4.5.1 Additional Models for Ignition Probability, Wildfire and PSPS Risk

Each utility is required to report details on the models and methodologies used to determine ignition probability, wildfire risk, and PSPS risk. This must include the following for each model – a list of all inputs, details of data elements used in the analysis, modeling assumptions and methodologies, input from Subject Matter Experts (SMEs), model verification and validation (e.g., equation(s), functions, algorithms or other validation studies), model uncertainty and accuracy, output (e.g., windspeed model) and applications of model in WMP (e.g., in selection of mitigations, decision-making).

The narrative for each model must be organized using the headings described below. A concise summary of the model(s) must be provided in the main body of the WMP in this section, with additional detail provided for each model in an appendix.

Purpose of model *– Brief summary of context and goals of model*

Relevant terms *– Definitions of relevant terms (e.g., defining "enhanced vegetation management" for a model on vegetation-related ignitions)*

Data elements *– Details of data elements used for analysis. Including at minimum the following:*

Scope and granularity (or, resolution) of data in time and location (i.e., date range, spatial granularity for each data element, see example table above).

Explain the frequency of data updates.

Sources of data. Explain in detail measurement approaches.

Explain in detail approaches used to verify data quality.

Characteristics of the data (field definitions / schema, uncertainties, acquisition frequency).

Describe any processes used to modify the data (such as adjusting vegetative fuel models for wildfire spread based on prior history and vegetation growth).

Modeling assumptions and limitations *– Details of each modeling assumption, its technical basis, and the resulting limitations of the model.*

Modeling methodology *– Details of the modeling methodology. Including at minimum the following:*

Model equations and functions

Any additional input from Subject Matter Experts (SME) input

Any statistical analysis or additional algorithms used to obtain output

Details on the automation process for automated models.

Model uncertainty *– Details of the uncertainty associated with the model. This must include uncertainty related to the fundamental formulation of the model as well as due to uncertainty in model input parameters.*

Model verification and validation *– Details of the efforts undertaken to verify and validate the model performance. Including at minimum the following:*

Documentation describing the verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach.

Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-world observations.

Modeling frequency *– Details on how often the model is run (for example, quarterly to support risk planning versus daily to support on-going risk assessments).*

Timeline for model development *– Model initiation and development progress over time. If updated in last WMP, provide update to changes since prior report.*

Application and results *– Explain where the model has been applied, how it has informed decisions, and any metrics or information on model accuracy and effectiveness collected in the prior year.*

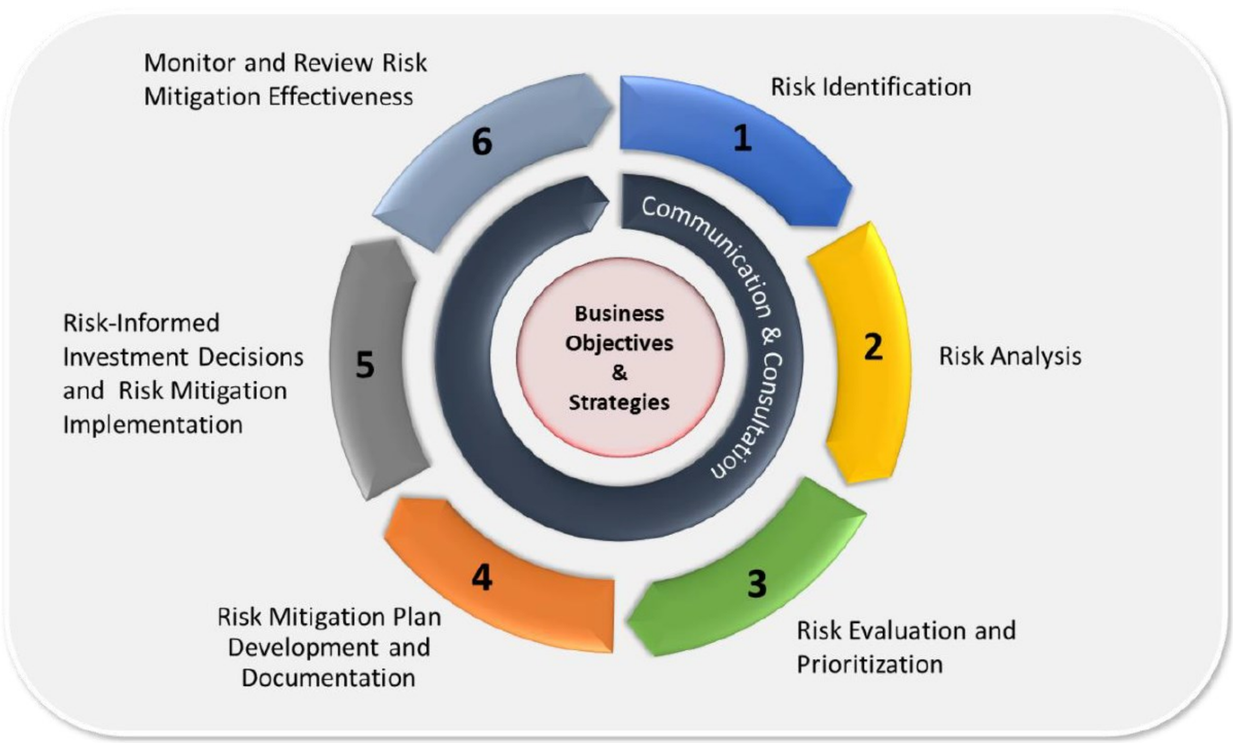
***Key improvements from working group** – For each model, describe changes which have been implemented as a result of wildfire risk modeling working group discussions. Provide a high-level summary of recommendations from the wildfire risk modeling working group.*

The risk models used are also described in **Sections 4.2.1** and **4.3** above. The models detailed in this section include the Risk-Based Decision-Making Framework – Risk Register, the Fire Safety Circuit Matrix, and the Ignition Probability and Consequence Mapping static model.

Risk-based decision-making model (Company-Wide Risk Methodology & Risk Register)

Purpose of Model: The risk-based decision-making model incorporates a risk-based decision-making framework into utility investments and programs to inform the General Rate Case (GRC) cycles. Accenture (formerly Davies Consulting) was contracted to assist BVES in developing this risk-based decision-making framework, which provides a process for identifying asset-related risks, consequence(s) of occurrence, frequency or likelihood of occurrence, driver(s) of the risk, and mitigation measures. This framework considers BVES's distribution assets and its Bear Valley Power Plant (BVPP). The results of the model aim to identify strategic objectives for approval, categorize top risks to BVES and its service area including new and emerging risks, and arriving at a risk-informed recommendation for future investments. This may also lead to modifying existing controls and implementation schedules.

Figure 4.5-1: BVES's High-Level Risk Management Process



Relevant Terms: See the table below for this response.

Table 4.5-1: Risk Based Decision Relevant Terms

Term	Definition
Risk	The potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various outcomes of an adverse event and their associated probabilities. Different stakeholders may have varied perspectives on risk.

Term	Definition
Inherent Risk	The level of risk that exists without risk controls or mitigations.
Event	An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address.
Frequency	Number of events generally defined per unit of time. (Frequency is often incorrectly treated as synonymous with probability or likelihood).
Probability	The relative possibility that an event will occur, probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certain we are that the event will occur. (Often informally referred to as likelihood or chance).
Impact (or Consequence)	The effect or outcome of an event affecting objectives, which may be expressed, by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Mitigation	Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.
Outcome	The final resolution or end result.
Risk Driver	Factor(s) that could cause one or more risks to occur (Risk driver may also be commonly referred to as “threat”).
Risk Response Plan	Collection of mitigations.
Control	Currently established measure that is modifying risk.
Alternative Analysis	Evaluation of different alternatives available to mitigate risk.
Residual Risk	Risk remaining after current controls.
Planned or Forecasted Residual Risk	Risk remaining after implementation of proposed mitigations.
Risk Score	Numerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time.
Risk Tolerance	Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.

Data Elements:

Scope and granularity: Data includes incident and safety findings, identified risk events with consequence mapping, field findings, and external sources of risk. These drivers are updated annually as new inputs are collected.

Frequency of data updates: Updates to the risk model occur on an annual basis to help determine any needed changes for capital investment or enhanced O&M activities.

Sources of data: The initial list of risk events is captured through record-keeping practices and risk team brainstorming sessions. These risks are reviewed and categorized with links to asset classes and affixed with a priority weight for the initial analysis. Additional inputs include activities poised to reduce the identified risk weight through WMP and operational execution. The raw data includes scores for frequency, reliability, compliance, quality of service, safety, environmental, and impact score, which result in the total risk score.

Table 4.5-2: Risk Register Risk Event Inputs

Risk		Risk Info		Risk Scoring Inputs						
ID	Risk Event	Reasonable Worst Case	Controls	Frequency	Reliability	Compliance	Quality of Service	Safety	Environmental
A	Wildfire - Public Safety	BVES caused wildfire results in multiple public fatalities or firefighter fatalities	Operational restrictions based on fire safety conditions, VM Program, Construction Stds to Grade A	Has not happened at BVES but has happened in Southern California at least once every 3 - 10 years.	Likely to include sub-transmission line; therefore, large portion of customers would have to be de-energized.	Serious lawsuits, and SED citations/ fines.	Outreach Program is required to rebuild trust on a sustained basis	Single fatality	Wildfire with long term impact
B	Wildfire – Significant Loss of Property	BVES caused wildfire starts in the southwest part of the service territory and destroys a portion of the village	Operational restrictions for the Radford Line, Inspections, VM	Has not happened at BVES but has happened in Southern California at least once every 3 - 10 years.	Likely to include sub-transmission line; therefore, large portion of customers would have to be de-energized.	Serious lawsuits, and SED citations/ fines.	Outreach Program is required to rebuild trust on a sustained basis	Smoke inhalation or injuries during evacuation	Large tracts of forest land destroyed, impact animal species and long-term effects
F	Loss of Energy Supplies	During extreme fire threat weather and conditions, such as a major Santa Ana wind event, SCE Doble, Cushenberry, and/or Bear Valley Lines are de-energized by SCE for PSPS for a period of 48 hours.	Bear Valley Power Plant Operations, Rolling Black-out Procedures	High frequency of SCE declaring "PSPS Consideration" supply circuits to BVES.	100% for more than 24 hours	While SCE responsibility, regulators would probe BVES on why it does not have sufficient internal baseload capacity.	Formal customer complaints to CPUC & outreach program required to build trust on substantial basis.	Public health problems like hypothermia, respiratory issues, heart problems.	Sewer plant bypasses processing and discharges effluent

Detailed approaches used to verify data quality: Data quality is verified through brainstorming sessions, SME input, and annual review of the model outputs. The data aligns with similarly tracked information imperative to the WMP update and quarterly reports. BVES ensures there is a 1-1 relationship between the inputs and outputs of the model across all enterprise risk practices. The System Safety and Reliability Engineer is also responsible for reporting any findings or discrepancies among the tracked data values and outputs. This employee also assists in quantifying the impact scores for the proposed mitigations and existing controls.

Characteristics of the data:

Risk Identification

Gather an initial list of risk events in a brainstorming session;

Review and categorize brainstormed risk events (e.g., link risk events to asset classes);

Select priority risk events for initial analysis; and

Document work involved in Risk Identification.

Risk Analysis

Perform initial analysis on selected risk events (e.g., is impact high, medium, or low?);

Select risk events for full analysis;

Perform full analysis on selected risk events (e.g., assess frequency and impact);

Assign an impact rating in six impact categories;

Develop Basis Document to capture assumptions and rationale behind scoring;

Communicate analysis results to affected parties;

Document work in Risk Register Risk Evaluation and Scoring;

Conduct calibration session to review total score for each fully analyzed risk;

Examine outliers and prepare for mitigation;

Communicate results to affected parties;

Document work in Risk Register Risk Mitigation;

Review existing controls for adequacy;

Develop new mitigations (if necessary); and

Document work in Risk Mitigations and Controls portion of Risk Register.

Data characteristics of the modeling results of the Risk Register are depicted in the table below.

Table 4.5-3: Mitigations Table Data Elements

Data Element Major	Data Element Minor	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment – Detail
Identifier	ID	Established	Established	N/A	N/A	Mitigation numeric ID
Mitigation Info	Mitigation Title	Established	Established	N/A	N/A	Title of mitigating activity
	Description	Established	Established	N/A	N/A	Description of mitigating activity
	Execution Period	2019 - ongoing	Quarterly	Circuit/Tier	N/A	Schedule of deployment
	Duration (years)	2019 - ongoing	Quarterly	Circuit/Tier	N/A	Years of deployment
	Equivalent Annual Cost	2019 - ongoing	Quarterly	Circuit/Tier	N/A	Forecasted annual spend
	Funding Type	2019 - ongoing	Quarterly	Circuit/Tier	N/A	O&M versus CAPEX
	Funding Source	2019 - ongoing	Quarterly	Circuit/Tier	N/A	Spending source
	Percent Completed or Implemented	2019 - ongoing	Quarterly	Circuit/Tier	N/A	Execution implementation (percentage)

Data Element Major	Data Element Minor	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment – Detail
	Mitigation Converted to Control	Annual	Annual	Circuit/Tier	N/A	Whether the mitigation is now an ongoing control
	Addresses Single-Risk vs Multiple-Risk	Annual	Annual	Circuit/Tier	N/A	Whether the mitigation addresses a single or multiple of risk drivers
	Risk ID	Established	Established	N/A	N/A	Associated Risk ID
	Risk Addressed	Annual	Annual	Circuit/Tier	N/A	Title of risk addressed
Un-Mitigated Scores	Frequency	Annual	Annual	Circuit/Tier	N/A	Risk frequency prior to mitigation activity
	Reliability	Annual	Annual	Circuit/Tier	N/A	Reliability score prior to mitigation activity
	Compliance	Annual	Annual	Circuit/Tier	N/A	Compliance score prior to mitigation activity
	Quality of Service	Annual	Annual	Circuit/Tier	N/A	Quality of service score prior to mitigation activity
	Safety	Annual	Annual	Circuit/Tier	N/A	Safety score prior to mitigation activity
	Environmental	Annual	Annual	Circuit/Tier	N/A	Environmental score prior to mitigation activity
	Impact Score	Annual	Annual	Circuit/Tier	N/A	Impact score prior to mitigation activity
	Risk Score	Annual	Annual	Circuit/Tier	N/A	Raw risk score
Mitigated Scores	Frequency	Annual	Annual	Circuit/Tier	N/A	risk frequency as a result of mitigation

Data Element Major	Data Element Minor	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment – Detail
	Reliability	Annual	Annual	Circuit/Tier	N/A	Reliability score as a result of mitigation
	Compliance	Annual	Annual	Circuit/Tier	N/A	Compliance score as a result of mitigation
	Quality of Service	Annual	Annual	Circuit/Tier	N/A	Quality of service score as a result of mitigation
	Safety	Annual	Annual	Circuit/Tier	N/A	Safety score as a result of mitigation
	Environmental	Annual	Annual	Circuit/Tier	N/A	Environmental score as a result of mitigation
	Impact Score	Annual	Annual	Circuit/Tier	N/A	Impact score as a result of mitigation
	Mitigated Risk Score	Annual	Annual	Circuit/Tier	N/A	Total mitigation risk score
	Risk Benefit	Annual	Annual	Circuit/Tier	N/A	Risk benefit gain score
Risk Spend Efficiencies	RSE	Annual	Annual	Circuit/Tier	N/A	Calculated risk spend efficiency
	Risk Elimination Progress	Annual	Annual	Circuit/Tier	N/A	Risk reduction score
	Remaining Risk Benefit	Annual	Annual	Circuit/Tier	N/A	Positive risk benefit
Chart Info	Title	Annual	Annual	Circuit/Tier	N/A	Title on results chart
	Caption	Annual	Annual	Circuit/Tier	N/A	Caption on results chart

Processes used to modify the data: BVES does not have a formalized process to modify the data inputs or characteristics at this time.

Modeling Assumptions and Limitations:

Initial Analysis - The Initial analysis requires the risk team to begin examining the priority risks selected during risk identification. In this step, SMEs collect basic information about each risk. This analysis will be entered into the risk register by the System Safety and Reliability Engineer. This information includes the following:

Title of Risk

Worst Reasonable Case

Risk Owner

Asset Class

Quick Evaluation of the risk event (High, Medium, or Low)

Developing Worst Reasonable Case - The worst reasonable case evaluation is based on plotting a range of outcomes along a distribution line and, for purposes of the risk discussion, choosing a scenario that identifies a reasonably probable worst-case outcome.

Once the risk team agrees on a Worst Reasonable Case, the impacts are defined on the most likely outcome of that Worst Reasonable Case. Given the worst reasonable case scenario, what is the most likely outcome in the six impact categories?

If sufficient data does not exist to produce a distribution to define the worst reasonable case, then the risk team will develop the worst reasonable case scenarios based on expert judgement.

Selecting the Top Tier Events (risk driver and consequential outcome)

Tier 1 Consequence

Has the potential to impact many processes;

Could affect more than four impact categories;

Risk velocity (speed on onset; the speed with which a risk manifests itself) is high; or

Could affect corporate level policies or goals and/or have effects across multiple parts of the company

Tier 2 Consequence

The risk event affects several processes;

The risk velocity is moderate; or

Could affect policies or goals and/or have effects across multiple facilities or operating regions within the company.

Tier 3 Consequence

Impacts one process;

The risk velocity is slow; or

Could affect a single department level policies or goals and/or be unique to a facility or operating region.

Evaluate Risk Impact Categories

BVES established Risk Impact Categories to assess the impact of an event. Table 1 defines these risk categories. BVES also established descriptions in each category that describe increasing levels of severity from level 1 (negligible) to level 7 (catastrophic). These Risk Impact Category Descriptions provide the risk team with guidance for analyzing and scoring risk events. The descriptions provide a consistent framework to assign an impact value (level 1 to 7) to risk events across all five impact categories. BVES utilizes SME review and industry practice to align worst cast impact scores. See the two tables below.

Table 4.5-4: Risk Impact Categories and Descriptions

Impact Category	Definition	Negligible (1)	Minor (2)	Moderate (3)	Major (4)	Extensive (5)	Severe (6)	Extreme (7)
Reliability	Ability of a process, asset, or system to perform its normal functions. Reliability is measured by end customer impact.	**Customer Impact**: Less than 20 customers affected. (e.g., 1 transformer out.)	**Customer Impact**: 20 - 500 customers affected. (e.g., loss of 1 section of a 4kV circuit.)	**Customer Impact**: 500-1,500 customers affected. (e.g., loss of partial circuit or entire circuit.)	**Customer Impact**: 1,500-5,000 customers affected. (e.g., loss of a section of a transmission line.)	**Customer Impact**: 5,000-10,000 customers affected. (e.g., loss of a section of a transmission line or shutdown of a major business customer.)	**Customer Impact**: 100% of customers out for less than 24 hours.	**Customer Impact**: 100% of customers out for more than 24 hours.
Compliance	Ability to meet regulatory/legal requirements. Impact seen in increased regulatory oversight, adverse regulatory actions, or penalties.	Informal complaint without fine or penalty.	**Regulatory:** Formal complaint from arbitrator (JPA) Notice to correct deficiency. **Legal:** Civil lawsuit filed.	**Regulatory:** Regulatory prescription on Company 3rd party complaint. **Legal:** Civil lawsuit filed but is settled out of court.	**Regulatory:** Adverse regulatory mandates and fines. **Legal:** A civil lawsuit with verdict or enforcement actions against the Company or a lawsuit with criminal charges.	**Regulatory:** Imposed direct regulatory oversight (Fines $$). **Legal:** Criminal charges filed but settled out of court.	**Regulatory:** Sarbanes-Oxley compliance violation (Fines $$$). **Legal:** Lawsuit with verdict against the Company and/or findings of criminal activity.	Company goes out of business (Fines $$$$). **Legal:** Criminal charge(s) with conviction.
Quality of Service (Cost, Quality, Complaints)	Measure of impact of a risk event on trust in Company and Company brand. Typically measured by cost, power quality, and customer complaints.	Little to no effects on cost, power quality, or customer complaints.	**Cost:** Meter failure at a small business. **Power Quality:** Customers exposed to power factor or RFI issues. **Complaints / Customer Service:** Release of inaccurate information to the public.	**Cost:** Moderate planning and/or construction cost overruns. **Power Quality:** Customers experiencing excessive flicker. **Complaints / Customer Service:** Increase in informal customer complaints.	**Cost:** Shutdown of a major commercial customer. **Power Quality:** Customers affected by BVES noise. **Complaints / Customer Service:** Increase in customer complaints to SR management.	**Cost:** Poor project decision-making that creates a stranded asset. **Power Quality:** Customers experiencing excessive numbers of momentary outages. **Complaints / Customer Service:** Increase in formal customer complaints to regulators.	**Cost:** Unhedged for a one-year period. **Power Quality:** Disruptive harmonics issues. **Complaints / Customer Service:** Damage to trust/ reputation requiring some outreach to state/local political officials.	**Cost:** Unhedged during a major price spike. **Power Quality:** Voltage outside of national code (e.g., voltage excursion outside IEEE, STD). **Complaints / Customer Service:** Loss of trust / reputation requiring sustained outreach to state and/or local political officials.

Impact Category	Definition	Negligible (1)	Minor (2)	Moderate (3)	Major (4)	Extensive (5)	Severe (6)	Extreme (7)
Safety	Degree to which a risk event leads to injury to a person (employee, contractor, or public). Typically measured by event severity (workforce or public). Common measure is OSHA recordable event.	Unplanned event that did not result in injury, illness, or damage but had the potential to do so. (e.g., “near miss” event.)	OSHA recordable public injury requiring first aid/medical care.	Lost time due to workplace accident. Public injury requiring hospitalization.	Long-term disability.	Life altering injury (i.e., one that results in permanent or long-term impairment or an internal organ, body function, or body part.) Examples include but are not limited to significant head injuries, spinal cord injuries, paralysis, amputations, or broken / fractured bones.	Single fatality (public, employees, or contractors).	Multiple fatalities (public, employees, or contractors).
Environmental	Degree to which a risk event negatively affects people, natural resources, or species. Can be measured by duration, hazard level, location, and size of event.	Event resulting in negligible but no long-term damage to the environment. (e.g., small oil leak contacting the ground, but no containment required.)	Event that can be contained in a small area. (e.g., oil leak in substation requiring active containment.)	Event that is quickly correctable. (e.g., small, confined fire that can be extinguished by BVES. Improper hazardous waste disposal that is not reportable.) (e.g., minor event like putting a paint can in the wrong bin.)	Excessive power plant emissions that are reportable OR Improper hazardous waste disposal that is reportable.	Events with potential for medium-term impact and/or require outside resources for support. (e.g., large leak or emissions release with long-term impact requiring support services.)	Events with potential for long-term impact requiring outside resources for support. (e.g., wildfire involving assets owned and/or managed by BVES in a large area requiring public response.) (e.g., event that could have an impact on wildlife.)	Events with potential long-term impact requiring outside support and resulting in substantial damage to a protected area or species. (e.g., large oil spill into navigable waters.)

Assess Frequency of Worst Reasonable Case - Frequency is defined as “number of events per unit of time.” It is a measure of how often a risk event has occurred or could occur. The frequency being measured is the frequency of the worst reasonable case of a specific risk event. Ensuring that users are measuring the frequency of the worst reasonable case and not the frequency of a risk event itself will help ensure consistency in analysis.

Table 4.5-5: Frequency Table

Level	Value	Occurrence
	7	Greater than 10 times per year
	6	1-10 times per year
	5	Once every 1-3 years
	4	Once every 3-10 years
	3	Once every 10-30 years
	2	Once every 30-100 years
	1	Once every 100+ years

Identify Hazards/Threats (Triggers)

Many risk events result from several different intermediate events. These “triggers” are essentially the causes of a risk. What factors acting together caused the risk to occur? Risk triggers can include human error (employee or contractor), mechanical failure of an asset, or a natural uncontrollable event (e.g., storm). For example, the causes or triggers of an aircraft accident could include pilot error, sensor failure, crew fatigue, and inclement weather. Any of these alone might not have caused an accident. Deconstructing the risk event this way may allow the risk team to get a more complete evaluation of the risk event and take a broader view of controls and mitigation actions in place.

Catalog Existing Controls

During Full Analysis, the risk team catalogs the controls already in place to address each risk. This information is added to the Controls and Mitigations portion of the risk register. Controls may apply to multiple risks, so there is a many-to-many relationship between controls and risks events.

Total Risk Score

The risk register calculates a total risk score from the data collected in risk analysis. The risk scores establish a relative ranking of risk events for discussion purposes. The score is a calculation based on an SME discussion of the impact and frequency associated with the worst reasonable case. The potential impacts of the worst reasonable case across the six impact categories are then scored between 1 and 7 (7 being the greatest severity). Once the impact is articulated, a frequency based on data and subject matter expertise is assigned to each worst reasonable case scenario. The risk register then applies a formula to create a score between 0 and 1,000,000,000.

Heat Map

The scores of risk events are plotted on a heat map matrix. BVES chose to use a 7 x 7 heat map matrix. The 7 x 7 matrix is consistent with leading practice in the utility industry and provides a better differentiation of risk events than a 3 x 3 matrix or a 5 x 5 matrix. Those maps produce a less distinct differentiation of risks. That is, many risks are high impact, low frequency and occupy the same space on the heat map, thereby limiting its usefulness in prioritizing areas of focus.

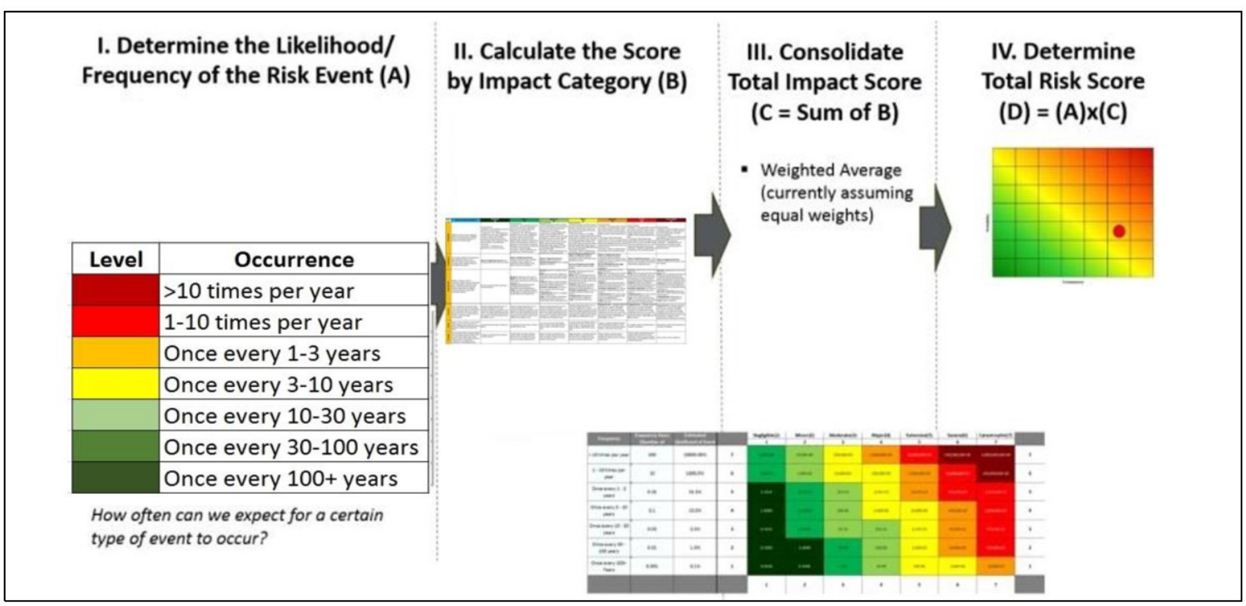
Modeling Methodology:

Model equations and functions: The input in risk identification and prioritization directly feed into the Risk Register modeling function. To produce the 7x7 safety matrix, BVES utilizes the following equation: Risk Score = Frequency * SUM I = 1 to 5 (CategoryWeight i x 10^Impact i). See the following tables for the calculation inputs and high-level methodology.

Table 4.5-6: Risk Log Score for 7x7 Matrix

Frequency	Frequency Years (Events/Year) [Min rate]	Frequency Years (Events/Year) [Max rate]	Frequency Value
> 10 times per year	10	100	31.6228
1 - 10 times per year	1	10	3.1623
Once every 1 - 3 years	0.3300	1.0000	0.5745
Once every 3 - 10 years	0.1000	0.3333	0.1826
Once every 10 - 30 years	0.0333	0.1000	0.0577
Once every 30 - 100 years	0.0100	0.0333	0.0183
Once every 100+ Years	0.0033	0.0100	0.0058

Figure 4.5-2: Risk Scoring Methodology



Any additional input from Subject Matter Experts (SME) input: BVES contracted with a risk management firm to establish the boundaries, scope, and inputs of the modeling capabilities prior to 2017. Currently, BVES is able to evaluate and run the model with SMEs assigned by the Operations and Planning Manager. The SMEs are responsible for providing technical knowledge and assistance to the System Safety and Reliability Engineer or Risk Owners as applicable in the application of the requirements of model execution. Specifically, SMEs provide technical assistance in determining:

Reasonable worst-case event for a top risk

Frequency of the reasonable worst-case event and impact scores

Existing controls in place

Mitigations and effect on frequency and impact scores

Other technical information as needed to support the System Safety and Reliability Engineer and/or Risk Owners as applicable in applying the risk management process to specified risks

Results are reviewed internally and also externally by an energy consulting firm, which operates to support all aspects of the WMP and compliance filings.

Any statistical analysis or additional algorithms used to obtain output: No additional statistical analysis was included to obtain output.

Details on the automation process for automated models: There are limited automation capabilities, and the raw data must be cleaned and sorted prior to executing the Risk Register.

Model Uncertainty: Sources to collect risk events include quantitative, recorded incidents as well as qualitative information gathered through contractor and employee interviews, surveys, questionnaires, and field observations. These results are subject to variability depending on unique experiences and are synthesized and discussed with the risk management team through brainstorming sessions to determine accuracy in reporting. Industry benchmarking, lessons learned, and external data collected from public resources are also subject to uncertainty, though result in minimal distortion of the model calibration.

Model Verification and Validation:

Documentation describing verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach: BVES does not have a formal verification basis to ensure equations are correctly solving, however, inputs are periodically checked to ensure accuracy with the calculations.

Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-work observations: Brainstorming sessions and quarterly discussions on risk events and initiative progress inform any updates to the inputs.

Model Frequency: The model run occurs annually in support of on-going risk assessments and initiative activity review.

Timeline for Model Development:

There have been no significant modeling changes since the 2021 WMP filing.

Once risk events are fully analyzed and scored, the risk team conducts an internal calibration session with a broad set of SMEs. The session focuses on those risks that are outliers or for which an SME may question the accuracy of the overall score. The SME or Risk Manager for each risk in question presents the material contained in the Basis Document and offers attendees the opportunity to discuss the risk scoring. Organizers should follow the guidance provided for brainstorming sessions, although the calibration sessions may be longer, depending on the number of risk evaluations that are discussed.

During annual calibration sessions, participants question assumptions and other inputs to risk scores to ensure alignment in how risks are evaluated. Once the calibration is complete, organizations are allowed to re-score any risk that has been successfully challenged.

Application and Results: See both **Figure 4.2-2** and **Figure 4.2-3** for updated outputs on risk spend ratios.

Key Improvements from Working Group: There have not been any direct improvements to the model as a result of the wildfire risk modeling working group discussions.

Key Improvements from Revision Notices: Based off revisions requests from 2021 and 2022 BVES has incorporated an RSE adjustment formula for projects that deal with both HFTD Tier 2 and Tier 3. The formula accounts for HFTD Tier 3 being 10% of the service area while only accounting for 0.7% of the total line miles. These factors allow for a unique RSE value for the Tier 3 portions of said projects. An example adjustment can be seen below:

Table 4.5-7: RSE Adjustment By Tier

Mitigation	RSE (Prior to Update)	RSE Tier 2	RSE Tier 3
Enhanced Vegetation Management Program	.19	.17	2.76

Fire Safety Circuit Matrix

Purpose of Model: The purpose of the model is to assist in determining a circuit-level risk that accounts for the current and planned mitigation activities that intend to reduce ignition potential. The model informs the planning period of the WMP considering changes to the risk profile as mitigations are executed over time. Outputs from the Risk Register and risk-based decision-making approach contributed significantly and are integrated in the model outputs of this matrix.

Relevant Terms: See the table below.

Table 4.5-8: Fire Safety Circuit Matrix Terms

Fire Safety Circuit Matrix – Data Terms	
Circuit	List of circuits located in High Fire-Threat Districts, which determines the scope of data collection and presentation within the matrix
Voltage	Kilovolt (kV) listing for each identified circuit
Fire Threat Tier	Acknowledgment of the fire threat Zone/Tier in which the circuit resides
# of Poles	The number of poles within the identified circuit segments
# of Tree Attachments	The number of tree attachments cataloged with the identified circuit segments
Bare Wire OH Circuit Miles	The length of bare wire overhead in circuit miles respective to the listed circuit
Covered Conductor OH Circuit Miles	The length of covered conductor overhead in circuit miles respective to the listed circuit
UG Circuit Miles	The length of undergrounded circuit in miles respective to the listed circuit
Substation	Associated substation, if any, by circuit
De-Energize in Unfavorable Condition	This column provides the allowance of which lines are permitted to be de-energized if fire potential threat exists
Exacter Survey (EMI & Infrared)	Determined if exacter survey process has started, is in progress, or is completed, by circuit
Pole Loading Program	Based on parameters of pole loading, GO 95, and age of the pole (70yrs.⁺), this column tracks the status of pole loading, intrusive testing, or pole replacement needs by circuit

Tree Attachment Removal Program	Determines the status of tree attachment removal activities by circuit
Tree Wire	The status of investigation determining the need for tree wire by circuit
Covered Wire	The status, by circuit, of covered conductor implementation and evaluation
Replace Expulsion Fuses	The status of evaluation of where fuse replacements from convention to current-limiting fuses are warranted, by circuit
IntelliRupters Pulsing Auto Reclosers	The status of determining whether fault interrupters are warranted on the identified circuit
System Instrumentation	The status, by circuit, of investigations of where further instrumentation is warranted
Switch Automation Opportunities	The status, by circuit, of evaluated opportunities for switch automation that enhance fire safety
Branch Line Fusing Options	The status of investigation, by circuit, of additional related fusing opportunities that enhance fire safety
Evaluate Protective Settings	The status of evaluation, by circuit, for protective setting determinations for breakers, switches, reclosers, fuse trip savers, fuses, and other trip devices
Consider Partial Undergrounding	The status of investigation, by circuit, of additional related fusing options

Data Elements:

Scope and granularity: Information is gathered on a quarterly basis for an update to the model that is performed semiannually. The scope is determined by each mitigation initiative metric unit and is not based on a time-sensitive designation. Latitude and longitude designations are recorded for the purpose of quarterly reporting updates in GIS, though is not imperative to the calculations of this model.

Frequency of data updates: Data is updated semiannually to ensure activities align with prioritization of highest risk circuits

Sources of data: The Fire Safety Circuit Matrix incorporates inputs from BVES's mitigation efforts and applies them to the risk drivers that drive the potential ignition likelihood and consequences. The matrix utilizes an algorithm with over 20 data inputs, which assess the risk of BVES's circuits using the risk factors and status of executed mitigation measures described in the WMP. This also incorporates electrical and vegetation inspection results with localized vegetation density along the circuit quantified from LiDAR survey results. Localized weather conditions are based on historical data, which are used to determine wind intensity factors for each circuit.

Detailed approaches used to verify data quality: To verify data quality, BVES leverages the internal quality checks performed on a quarterly basis to track mitigation executions schedules. Information presented in the quarterly reports and internal metrics are directly integrated into the model functions. This model does not include any direct confidence ranges for each modeling component and uses the base weighted scoring mechanism to determine the risk range, score, and circuit prioritization for wildfire mitigation efforts.

Characteristics of the data: The following risk factors have an impact on making a circuit "high risk" with respect to wildfire:

Length of overhead bare wire (longer length is higher risk);
Voltage (higher voltage is higher risk);
Availability of fuel (higher vegetation density is higher risk);
Susceptibility to high winds (higher wind area is higher risk);
Susceptibility to pole failure (higher number of wood poles is higher risk);
Number of conventional (expulsion) fuses (higher is higher risk);
Number of Tree attachments (higher number is higher risk);

Number of Uncorrected Level 1 deficiencies (higher number of uncorrected Level 1 wind area is higher risk);
Number of Uncorrected Level 2 deficiencies (higher number of uncorrected Level 1 wind area is higher risk); and
Rank in Top Ten worst performing circuits (#1 is highest risk, then #2, etc.).

Data characteristics of the modeling results of the Fire Safety Circuit Matrix are depicted in the table below.

Table 4.5-9: Fire Safety Circuit Matrix Data Characteristics

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment-Detail
Circuit	N/A	N/A	Tier Designation	N/A	ID of Circuit
Substation	N/A	N/A	Tier Designation	N/A	Applicable Substation
Wildfire Risk Group	2019 Ongoing	Semiannually	Tier Designation	N/A	Resulting calculation of risk score
Overall Risk Weighting	2019 Ongoing	Semiannually	Tier Designation	N/A	Resulting calculation of risk score divided by total score
Risk Ranking	2019 Ongoing	Semiannually	Tier Designation	N/A	Ranking of circuits based on risk determination
Voltage (kV)	N/A	N/A	Tier Designation	N/A	Circuit voltage class
High Fire Threat District Tier	N/A	N/A	Tier Designation	N/A	HFTD Tier designation
Vegetation Density	2019 Ongoing	Semiannually	Circuit ROW within Tier designation	N/A	High, Medium, Low ranking
Wind Intensity	2019 Ongoing	Quarterly	Circuit ROW within Tier designation	Date, hour applicable to circuit mile and county	High = 100, Medium = 25, Low = 5
# of Customers	2019 Ongoing	Semiannually	Applicable to each circuit	N/A	Customers accounting for circuit
# of Wood Poles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of wood poles along the circuit
# of Fire Resistant Composite Poles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of installed/ hardened fire-resistant poles

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment-Detail
# of LWS Poles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of LWS poles along the circuit
# of Ductile Iron Poles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of Ductile Iron poles along the circuit
Bare Wire OH Circuit Miles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	circuit miles of bare wire on applicable circuit
Covered Conductor OH Circuit Miles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	circuit miles of covered conductor on applicable circuit
UG Circuit Miles	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	circuit miles of undergrounding on applicable circuit
# of Tree Attachments	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	number of remaining tree attachments on the circuit
# of Expulsion Fuses	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	number of expulsion fuses remaining on the circuit
# of Level 1 Deficiencies to be Corrected	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of Level 1 deficiencies found to be corrected from the prior quarter
# of Level 2 Deficiencies to be Corrected	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of Level 2 deficiencies found to be corrected from the prior quarter
Top Ten Worst Performing Circuit (1=Worst NR=Not Ranked)	2019 Ongoing	Semiannually	Applicable to each circuit	N/A	From 1 - 10 or NR; identified as the top ten worst performing circuit based on risk profile and deficiencies found
Pole Loading Program (Percent Complete)	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Circuit proportion of pole loading inspections (applicable to number of poles on circuit)
Tree Attachment Removal Program	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	number of remaining tree attachments removed on the circuit
Replace OH Bare Wire with Covered Conductor	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Circuit miles replaced with covered conductor

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment-Detail
Replace Expulsion Fuses	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of expulsion fuses replaced on the circuit
Evacuation Route Hardening	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	number of circuit miles hardened for evacuation routes
Circuit Sectionalized to Reduce PSPS Impact	2019 Ongoing	Quarterly	Applicable to each circuit; span	N/A	Circuit span/portion sectionalized to mitigate impact, scope, and scale of PSPS activations
Fault Indicators	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of fault indicators implemented on circuit
Replace AR with Pulse Conditioned Intellirupter	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Number of replacements of automatic reclosers with pulse conditioned Intellirupter devices
Circuit Meters Installed On All Phases Remotely Monitored	2019 Ongoing	Quarterly	Applicable to each circuit; phases	N/A	Number of phases installed with remote monitors
Install FLISR	2019 Ongoing	Quarterly	Applicable to each circuit	N/A	Installation of FLISR applicable to the circuit
Enhanced Vegetation Management	2019 Ongoing	Quarterly	Tier Designation	N/A	Circuit miles of enhanced vegetation management performed
GO-165 Ground Patrol	2019 Ongoing	Quarterly	Entire territory	N/A	Circuit inspection activities with ground patrols
GO-165 5-Year Inspections	2019 Ongoing	Quarterly	Entire territory	N/A	Circuit inspection activities with detailed patrols
GO-165 Intrusive Inspections	2019 Ongoing	Quarterly	Entire territory	N/A	Circuit inspections with intrusive review activities
Annual LiDAR Survey	2019 Ongoing	Quarterly	Entire territory	N/A	Circuit miles covered by LiDAR inspections
3rd Party Annual Ground Patrol	2019 Ongoing	Quarterly	Entire territory	N/A	Annual third-party ground patrol in circuit miles
GO-174 Substation Inspections	2019 Ongoing	Quarterly	Entire territory	N/A	Number of substations inspected within the service area
Substation Electrical Equipment Preventative Maintenance	2019 Ongoing	Quarterly	Tier Designation	N/A	Number of substations receiving preventative maintenance

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment-Detail
Exacter Survey	2019 Ongoing	Quarterly	Tier Designation	N/A	circuit applicable to exacter surveys
Fly-over Video Inspection Survey	2019 Ongoing	Quarterly	Tier Designation	N/A	circuit applicable to fly-over activities
Evaluate Protective Settings & Optimize for Fire Safety	N/A	Annually	N/A	N/A	Evaluation for optimized settings

Processes used to modify the data: No processes are in place nor are applicable to modifying the data to be used within the model.

Modeling Assumptions and Limitations: Detailed climate conditions and forecasted periodic cases (e.g., 50-year or 100-year conditions) are not currently addressed in the Fire Safety Circuit Matrix. BVES takes the actual performance over the last six months as data inputs for the model run functionality.

Modeling Methodology: The performed initiatives are subtracted from the risk score if execution schedules are behind, issues for completion are found, or other periodic incidents where these mitigation measures are delayed. This matrix is interdependent on the Risk Register construct and risk-based decision-making methodology.

Model equations and functions: The Wildfire Risk Group (WRG) Score is calculated using the following equation:

WRG = Bare Wire OH Circuit Miles on an identified circuit within Tier 2 or 3 presented with a worst performing circuit rating +(# of found conventional fuses + # of tree attachments remaining + # of level 2 deficiencies to be corrected + rank of work performing circuit rating) – the pole loading program percent complete multiplied by the number of wood poles – the fault indicator percentage – (whether the circuit is subject to enhanced vegetation management, whether a GO 165 ground patrol is performed, subject to GO 165 five year inspections, GO 195 intrusive inspections, whether the circuit is subject to a bi-annual LiDAR survey, third party annual ground control, or GO 174 Substation inspections).

The positive data elements imply higher risk scoring. BVES assumes the available risk driver characteristics of the circuits and removes the positive, risk-reducing activities to engender a net result score that accounts for the total available risk of the circuit. This methodology categorizes the circuit with its current risk drivers less mitigations.

Table 4.5-10: Risk Scoring Criteria Amounts

Risk Scoring Amount (Adds to Risk Score)
34.4 kV = 500 & 4 kV = 50
HFTD Tier 3 = 10000 x Bare Wire Circuit Miles and HFTD Tier 2 = 50 x Bare Wire Circuit Miles
Bare Wire Circuit Mile x 200
High Density = 100 x Bare Wire Circuit Miles; Med Density = 25 x Bare Wire Circuit Miles; and Low Density = 5 x Bare Wire Circuit Miles
High Wind Area = 100 x Bare Wire Circuit Miles; Med Wind Area = 25 x Bare Wire Circuit Miles; and Low Wind Area = 5 x Bare Wire Circuit Miles
# of Conventional Fuses x 2
# of Tree Attachments x 4
# of Level 1 Deficiencies x 1000
# of Level 2 Deficiencies x 100
Circuit Ranking: #1 = 1000, #2 = 900, #3 = 800, #4 = 700, #5 = 600, #6 = 500, #7 = 400, #8 = 300, #9 = 200, #10 = 100, & Not Ranked = 0

Table 4.5-11: Risk Mitigation Factors & Scoring Criteria

Risk Mitigation Factors	Risk Scoring Amount (Subtracts from Risk Score)
Pole Loading Program (Percent Complete)	(Number of Wood Poles x Percent Complete) x 5; NA = 0
FI Program (Percent Complete)	(Percent Complete * 100) x 2; NA = 0
Enhanced Vegetation Management	On Schedule (Green) = Bare Wire Circuit Miles x 2; Behind Schedule (Red) = 0
GO 165 Ground Patrol	In Periodicity (Green) = Bare Wire Circuit Miles x 2; Out Periodicity (Red) = 0
GO 165 5-Year Inspections	In Periodicity (Green) = Bare Wire Circuit Miles x 2; Out Periodicity (Red) = 0
GO 165 Intrusive Inspections	In Periodicity (Green) = Number of x 2; Out Periodicity (Red) = 0
Bi-Annual LiDAR Survey	In Periodicity (Green) = Number of Wood Poles x 2; Out Periodicity (Red) = 0
3rd Party Annual Ground Patrol	In Periodicity (Green) = Bare Wire Circuit Miles x 2; Out Periodicity (Red) = 0
GO 174 Substation Inspections	In Periodicity (Green) = Bare Wire Circuit Miles x 2; Out Periodicity (Red) = 0

Any additional input from Subject Matter Experts (SME) input: BVES does not use direct SME review to verify results but does work with staff and consultants to interpret the outputs as it relates to future WMP updates.

Any statistical analysis or additional algorithms used to obtain output: No additional algorithms are utilized in updating the Fire Safety Circuit Matrix.

Details on the automation process for automated models: This model is not yet automated, nor does it utilize machine learning.

Model Uncertainty: Input parameters are subject to error based on recordkeeping practices, consultant insight, or field activity findings. BVES internally reviews the updated metrics to help to ensure uncertainties are mitigated and rectified when encountered.

Model Verification and Validation:

Documentation describing verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach: BVES does not have a formal verification basis to ensure equations are correctly solving, however, inputs are periodically checked to ensure accuracy with the calculations.

Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-work observations: Brainstorming sessions and quarterly discussions on risk events and initiative progress inform any updates to the inputs.

Model Frequency: The model run occurs semi-annually in support of on-going risk assessments and initiative activity review.

Timeline for Model Development: BVES has not made any modifications to the Fire Safety Circuit Matrix since the last WMP filing. As part of the planned work to revise ignition and risk modeling, BVES may consider subsequent revisions to the calculations or modeling approach.

Application and Results: In conjunction with the modeling description of the Risk Register outputs, BVES evaluates enterprise risk using a risk-based decision-making framework to prioritize identified wildfire risk and evaluate wildfire risk mitigation. Both the Fire Safety Circuit Matrix and the modeling description of the Risk Register produce prioritization categorization for high-risk assets and regions. The combination of these methods allows for both a comprehensive analysis of enterprise-wide safety risk and wildfire related assessment to generate an effective proxy wildfire ignition risk assessment. BVES Risk-Based Decision-Making Framework and resulting Risk Register effectively target circuits and assets to assure initiatives that provide the greatest mitigation benefits are prioritized. The following programs directly mitigate the risk factors that make a circuit "high risk" with respect to wildfire by removing or significantly reducing the frequency (or likelihood) of certain risk factors occurring (while the programs are in progress, they partially reduce the risk):

Covered wire program (removes bare wire)
Undergrounding facilities (removes bare wire)
Replace conventional fuses (removes expulsion fuses)
Tree Attachment Removal Program (removes tree attachments from system)

The following programs mitigate the above risk factors that make a circuit "high risk" with respect to wildfire by reducing the frequency (or likelihood) of the certain risk factors occurring:

Pole Strengthening (Pole Loading Assessment & Remediation Program) (reduces susceptibility of wood poles to failure)
Installing Fault Indicators (reduces time to locate faults)
Replace AR with Pulse Conditioned IntelliRupter (reduces energy on a line being tested after a fault)
Install Remotely Monitored Circuit Meters on All Phases (immediately provides indication of outage or abnormal circuit parameters reducing detection time of faults)
Install Fault Localization Isolation Service Restoration (FLISR) (automatically isolates and de-energizes faults)
Enhanced Vegetation Management (reduces fuel in immediate vicinity of lines from making contact with bare wire)
GO-165 Ground Patrol (detects Level 1 and 2 vegetation and facilities discrepancies and other discrepancies that may lead to safety issues; also detects if previously noted discrepancies have been properly cleared)
GO-165 5-Year Inspections (detects Level 1 and 2 vegetation and facilities discrepancies and other discrepancies that may lead to safety issues; also detects if previously noted discrepancies have been properly cleared)
GO-165 Intrusive Inspections (detects pole strength integrity issues)
Bi-Annual LiDAR Survey (detects Level 1 and 2 vegetation and facilities discrepancies and other discrepancies that may lead to safety issues; also detects if previously noted discrepancies have been g properly cleared)
3rd Party Annual Ground Patrol (detects Level 1 and 2 vegetation and facilities discrepancies and other discrepancies that may lead to safety issues; also detects if previously noted discrepancies have been properly cleared)
UAV Fly-over Inspections (detects Level 1 and 2 vegetation and facilities discrepancies and other discrepancies that may lead to safety issues; also detects if previously noted discrepancies have been properly cleared)
GO-174 Substation Inspections (detects substation equipment issues that may fault or failure to open on a fault down circuit)
Substation Electrical Equipment Preventative Maintenance (detects substation equipment issues that may fault or failure to open on a fault down circuit)

The following programs reduce the severity of wildfire or PSPS:

Evacuation Route Hardening (reduce likelihood of overhead facilities falling into an evacuation route or causing other damage)
Circuit Sectionalized to Reduce PSPS Impact (reduce number of customers impacted by PSPS events)

Results of the matrix are presented in Error! Reference source not found. and **Table 4.3-2** in **Section 4.3**.

Key Improvements from Working Group: There have not been any direct improvements to the model as a result of the wildfire risk modeling working group discussions.

Ignition Probability Risk Model / Mapping

Purpose of Model: The model aimed to address four separate subtasks of the Risk Mapping Program including: ignition probability mapping showing the probability of ignition along overhead electric lines and equipment, match drop simulations showing the potential wildfire consequence of ignitions that occur along electric lines and equipment under current (2021) conditions, match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment under future (2050) conditions, and summarized risk maps showing overall ignition probability and estimated wildfire consequence/risk under current and future conditions.

Relevant Terms:

RTMA – Real Time Mesoscale Analysis: this provided hourly estimates of sensible weather variables on a 2.5 km grid throughout the continental United States

Fuel Bed – 2021 California fuelscape (Pyrologix / USFS R5) at 30 m resolution

WRF – Weather Research and Forecasting using dynamically downscaled data that is climate adjusted for mid-century conditions. This dataset is initialized with global climate models from the 6th Coupled Model Intercomparison Project (CMIP6) for hourly conditions at 3.0 km resolution with adjustments in years 2046-2055

Data Elements:

Scope and granularity: This model utilized 2.5 km grid resolution using RTMA data to determine the weather conditions at the time and exact location of the ignition event. The metric units are in terms of ignition rate, which is depicted as ignition/line mile/hour. Lines are measured by 100 poles per span of the circuit.

Frequency of data updates: The model and subsequent mapping result are static based off information gathering in 2021.

Sources of data: The model utilized CPUC-reportable fire ignition data. This, in conjunction with gridded meteorological data, provided the ability to quantify power line ignition rates as a function of wind gust speed and fuel bed ignition probability. Wind gust speed and fuel bed loading data is derived from inputs recorded by the NFDRS as a function of fine fuel moisture content and temperature/humidity. NOAA climate change parameters are used to determine ignition risk in 2050.

Detailed approaches used to verify data quality: Data quality is determined through existing means of verification as the sources were captured from living models and recorded fire incidents submitted by the large IOUs.

Characteristics of the data: The wildfire consequence was modeled using ELMFIRE. The inputs are listed below with applicable data elements for the *collection period*, *collection frequency*, *spatial granularity*, and *temporal granularity*:

Current (2021) climatology/weather: NOAA NCEP RTMA for hourly gridded fields of temperature, relative humidity, wind speed, and direction at 2.5 km resolution from 2011-current conditions.

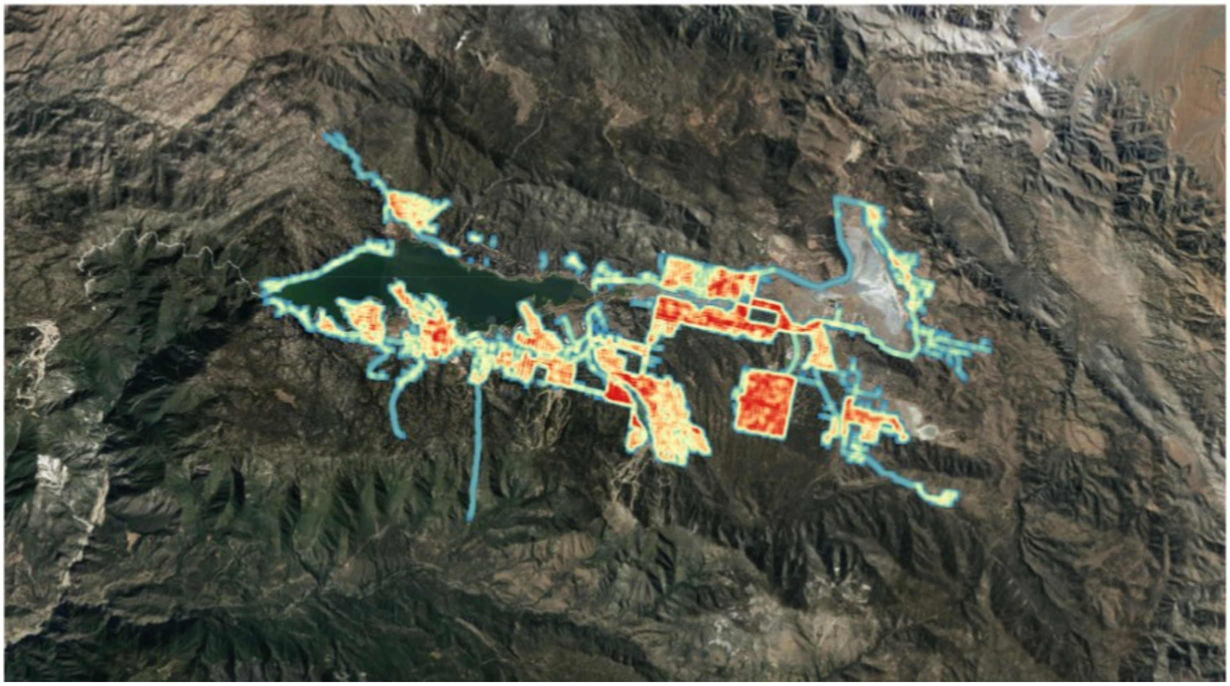
Future (2050) climatology/weather: Dynamically downscaled WRF initialized with global climate models from the 6th Coupled Model Intercomparison Project (CMIP6) for hourly gridded fields of temperature, relative humidity, wind speed, and direction at 3 km resolution. A temporal block from years 2046-2055 was selected for this analysis.

Fuel and topography: Pyrologix 2021 California Fuelscape, which provides surface and canopy fuel layers and topography at 30 m resolution. No adjustments are made for 2050 presented conditions.

Structures: Microsoft building footprint dataset, 2021 update with no adjustments made for 2050 conditions.

Overhead electrical network: BVES provided REAX Engineering with the GIS data representing all lines and electrical assets. The data assisted in calculating the conductor length per unit area on each 30 m fuel and topography grid cell, and a 5x5 filter was also used to smooth out the data into the adjacent grid cells as ignitions may not directly occur on power lines. This resulted in a buffer zone around the conductors. The resultant conductor length per unit area was placed into a raster as part of the analysis. The resulting Figure is depicted below.

Figure 4.5-3: BVES Overhead Electrical System Density (mi/mi^2)



Processes used to modify the data: No processes were utilized to modify the data. Units of measurements were converted through conventional means.

Modeling Assumptions and Limitations: Integration of potential ignitions avoided due to PSPS is not applicable as neither consequence resulted in significant data findings for BVES due to lack of ignition events and activated PSPS protocols.

For future/2050 climate-adjusted modeling, fuels, and structure footprints are kept constant at the current/2021 baseline.

Impacts of routine and enhanced vegetation management activities (including tree-trimming, tree-removal, inspections, etc.) are not considered in this model. Asset data (including asset age, health, inspection results, type, etc.) is not currently incorporated into this model. Impacts of system hardening and other initiative efforts is not currently incorporated into this model. Ingress or egress routes are not directly addressed by this risk model.

AI/machine learning was not used. Ignition modeling is a correlation based on historical ignitions and weather data. Consequence modeling is based on ELMFIRE,[31] additional details can be found in publication listed in the footnote.[32]

WRF was used to dynamically downscale global climate models (GCMs) from the 6th Coupled Model Intercomparison Project (CMIP6). A 10-year block of this data (hourly, 3 km resolution) centered around 2050 is used in fire ignition and spread modeling to quantify mid-century conditions.

Ignition probability is modeled from empirical ignition data from two California IOUs and differences in system operation (reclosing, fast trip), maintenance, vegetation management, etc. are not accounted for.

[31] Lautenberger, C., “Wildland Fire Modeling with an Eulerian Level Set Method and Automated Calibration,” Fire Safety Journal 62: 289-298 (2013).

[32] Lautenberger, C., “Mapping Areas at Elevated Risk of Large-Scale Structure Loss Using Monte Carlo Simulation and Wildland Fire Modeling,” Fire Safety Journal 91: 768-775 (2017).

Additionally, insufficient ignition data were available to account for differences between ignition rates on distribution and sub-transmission/transmission lines.

Modeling Methodology:

Model equations and functions: Publicly available utility ignition data reported to CPUC and OH electrical network filed with WMPs were analyzed to quantify ignition rate (ignitions / 100 pole miles / hour) as a function of wind gust speed, fuel moisture, and temperature. Weather conditions at ignition location & time of ignition determined from gridded meteorological data and normalized by historical values that the entire overhead network "sees". Ignition rate was found to be an exponential function of wind gust speed, fine dead fuel moisture content, and fuel temperature.

> Climate conditions for 2021 are derived from the RTMA product from the NOAA / National Centers for Environmental Prediction. This provides hourly gridded (2.5 km) fields of weather conditions from 2011 to current. Future (2050) climate conditions are modeled using a downscaled global climate model developed by UCLA's Department of Atmospheric and Oceanic Sciences. Specifically, the WRF was used to dynamically downscale global climate models (GCMs) from the 6th Coupled Model Intercomparison Project (CMIP6). BVES is using a 10-year block of this data (hourly, 3 km resolution) centered around 2050 in its fire ignition and spread modeling to quantify differences in fire ignition and spread between current (2021) and future (2050) climate conditions.
>
> 10-year climatology (2021 and 2050) was used to drive ignition and spread simulations with 1,000,000 years of fires simulated for current and climate-adjusted conditions. The simulation duration varied from 24 hours to one week.

Any additional input from Subject Matter Experts (SME) input: Systems used to verify the model outputs, including verifier (subject matter experts, third-party) and description of implementing lessons learned – Upon completion of said model BVES will evaluate the need to verifying systems, with staff or using a third-party verifier (Third-Party SME).

Any statistical analysis or additional algorithms used to obtain output: To facilitate analysis of the ignition rate as a function of wind gust and ignition probability, the wind gust units were binned in 2 mph increments from 0 mph to 100 mph for a total of 50 wind gust columns. The ignition probability was then binned in 2 percent increments from 0/00 – 1.00 for a total of 50 ignition probability rows. Gridded RTMA data was used in conjunction with known conductor density rasters to determine the number of line mile hours for the overhead electrical system in discrete ignition probability/wind gust bins. This is performed by looping temporally over determining the corresponding 2 percent ignition probability multiplied by 2 mph wind gust bins. The number of line mile hours in that bin was then incremented by the number of line mile hours in the RTMA grid cell. This was repeated for the CPUC ignition data from 2014 – 2020. To provide annualized line mile-hours per bin, the result was divided by seven years (record provided). The results depicted, through a scatter heat map plot, the line mile-hours as a factor of logarithmic scale (Log base 10). The results that were utilized in plotting BVES's territory though is confidential and proprietary.

Details on the automation process for automated models: This model is not automated, but rather, plots unit data sets as a function of the analysis on a spatial data map.

Model Uncertainty: BVES does not currently have confidence information for each modeling component, including how such confidences were determined.

Fires are modeled as unsuppressed for a duration of 48-hours because all operational fire models, including ELMFIRE, cannot reliably model fire suppression. Impacted structures were tallied as the number of structures within a modeled fire perimeter and did not necessarily correspond to damaged or destroyed structures. Factors that affect structure vulnerability (e.g., roof and exterior wall construction, defensible space, etc.) were not addressed.

There is considerable uncertainty around future climate, and the modeled future climate data is based on a single near worst case climate scenario.

Model Verification and Validation:

Documentation describing verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach: The model which generated the static risk maps/images uses contractor proprietary information with established verification steps.

Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-work observations: Using publicly available information, the model captured insight from real-world observations, ignition events, and meteorological conditions as well as industry accepted projections for climate change impacts.

Model Frequency: The results of the modeling effort are static. The activity took place over 2021 and has concluded at the end of the year with the production of the ignition risk maps.

Timeline for Model Development: BVES contracted with REAX Engineering to develop a series of ignition probability and consequence mapping using historical, present, and future data for a static illustration of territory-wide risks through wildfire ignition simulations. This effort concluded in 2021.

Application and Results: In consequence modeling, uncertainty is addressed using large-scale Monte Carlo fire spread modeling to model hundreds of thousands of fires under past and future weather/climate scenarios. Risk is the product of probability and consequence. Ignition modeling directly quantifies probability. Fire spread modeling quantifies consequence as impacts to structures and acres burned. These are multiplied together to quantify risk. All modeling of this type is inherently uncertain. BVES understands this, but can still determine relative risks from the models, prioritize those risks more likely to occur or cause catastrophic outcomes, and work to reduce and mitigate those risks.

The resulting below maps are the products of the analysis.

Figure 4.5-4: Modeled Fire Area (48-hr, Unsuppressed)

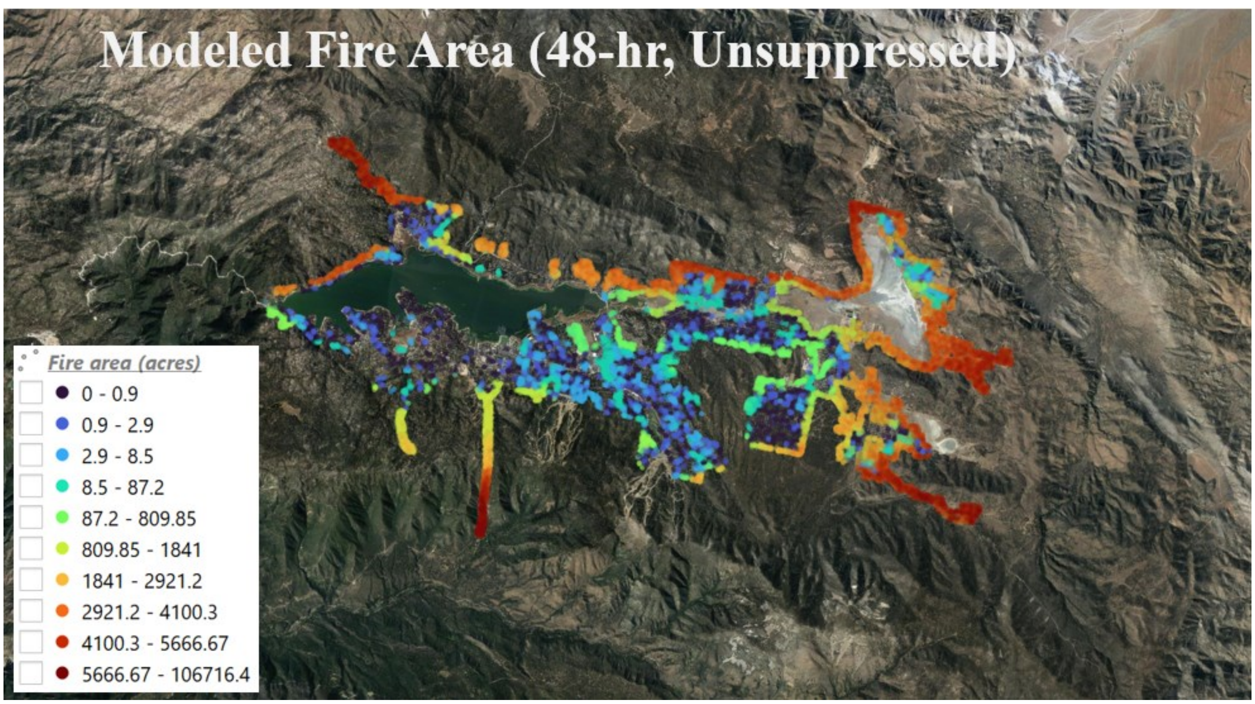


Figure 4.5-5: Modeled Risk from Power Line Ignitions (Based on Fire Area)

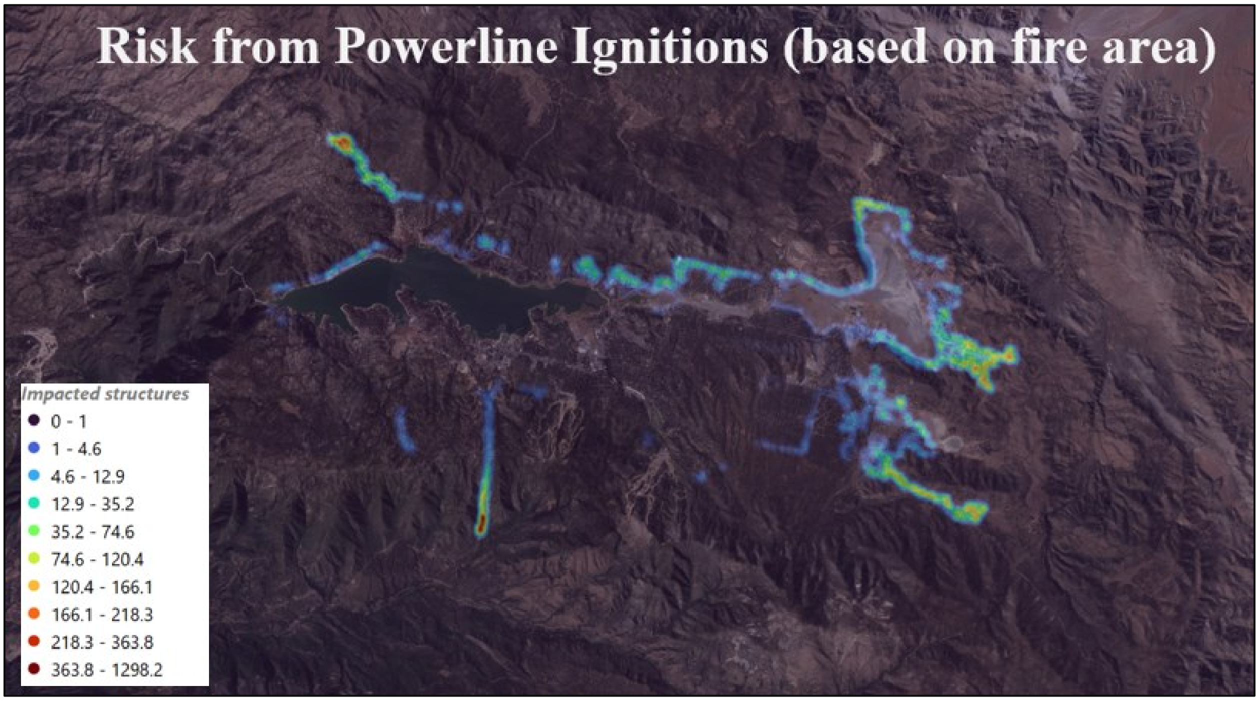


Figure 4.5-6: Modeled Structural Impacts (48-hr, Unsuppressed)

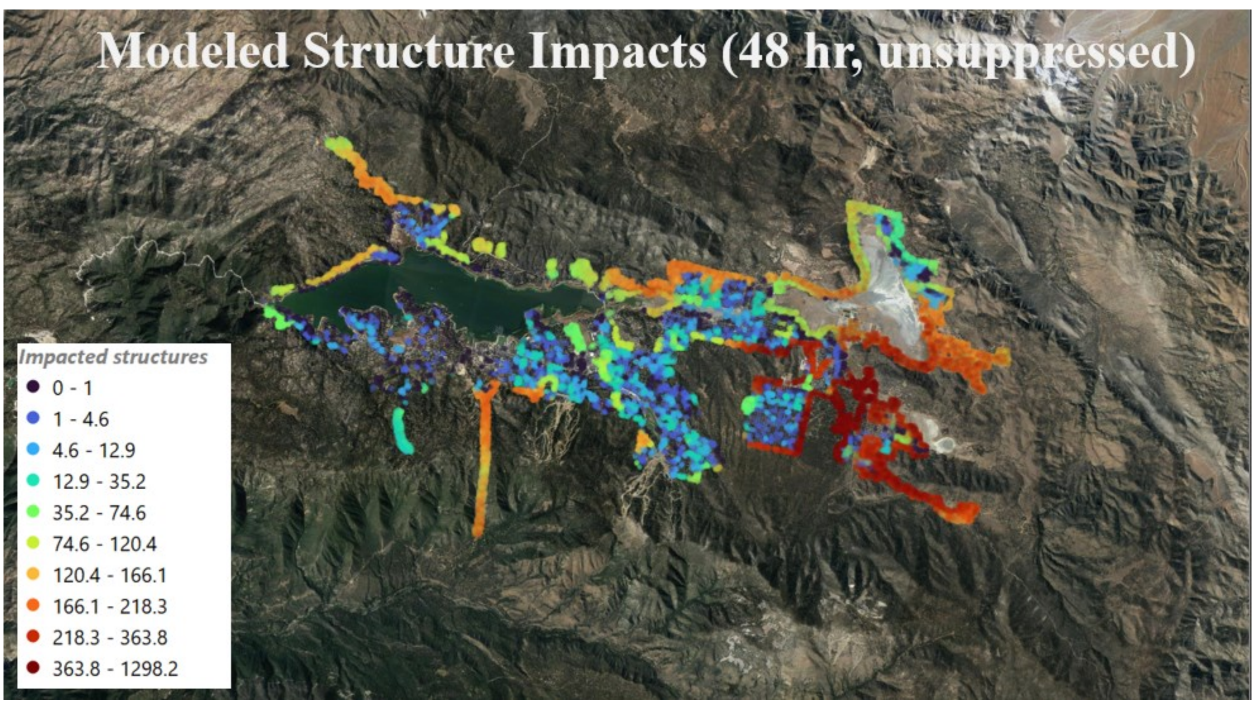


Figure 4.5-7: Modeled Risk from Power Line Ignitions (Structures)

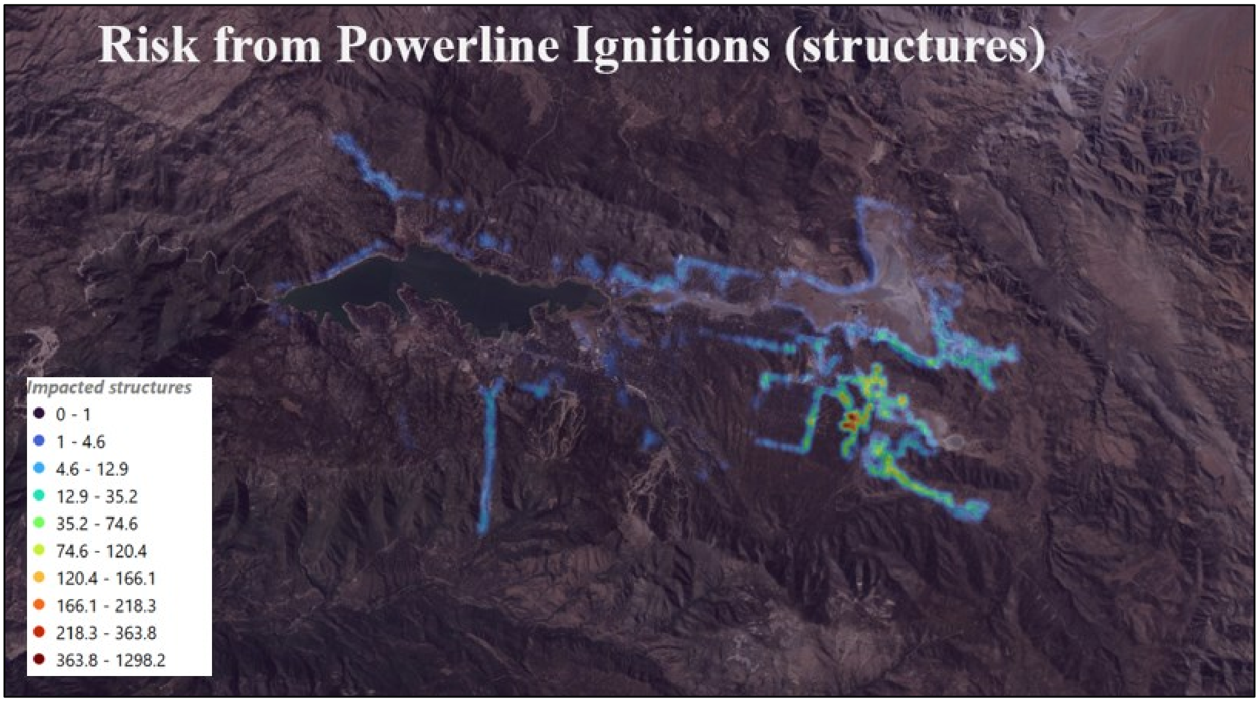
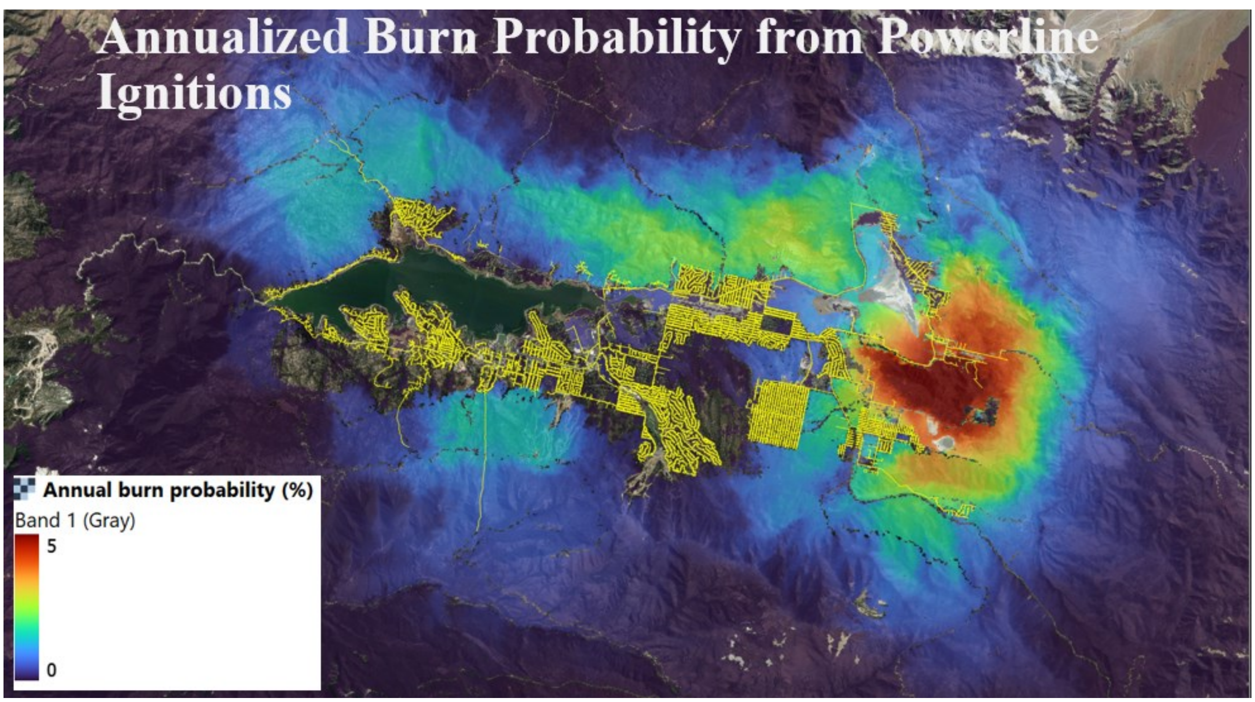


Figure 4.5-8: Annualized Burn Probability from Power Line Ignitions



Key Improvements from Working Group: BVES presented these models and maps to the working group in October 2021. Similar utilities have utilized this firm and methodology, which provided insight with how the model has optimized planning practices. Key improvements and takeaways have directed BVES to consider a modeling construct with more automation and live updates captured from meteorological data and its own weather stations. These initial maps provide sufficient direction in short-term planning. Future ignition probability and consequence models will include in-situ data collection and plotting mechanisms and a facilitated platform to draw simulations when needed for evaluation.

4.5.2 Calculation of Key Metrics

Report details on the calculation of the metrics below. For each metric, a standard definition is provided with statute cited where relevant. The utility must follow the definition provided and detail the procedure they used to calculate the metric values aligned with these definitions. The utility must cite all data sources used in calculating the metrics below. In addition, the utility must include GIS layers showing Red Flag Warning (RFW) frequency and High Wind Warning (HWW) frequency (use data from the previous 5 years, 2016-2021), as well as GIS layers for distribution of Access Functional Need (AFN) customers, and urban/rural/highly rural customers, and disadvantaged communities[33] in its service territory.

> ***Red Flag Warning overhead circuit mile days** – Detail the steps to calculate the annual number of red flag warning (RFW) overhead (OH) circuit mile days. Calculate as the number of circuit miles that are under an RFW multiplied by the number of days those miles are under said RFW. Refer to the National Weather Service (NWS) Red Flag Warnings. For historical NWS RFW data, refer to the Iowa State University archive of NWS watch / warnings.[34] Detail the steps used to determine if an overhead circuit mile is under a RFW, providing an example of how the RFW OH circuit mile days are calculated for a RFW that occurred within the utility service territory over the last five years.*

BVES tracks the Red Flag Warning (RFW) issuances through the National Weather Service (NWS) to maintain safe operational practices for field crew as well as in support of the WMP's situational awareness procedures. BVES has a single zone attributed to San Bernardino County that accounts for these RFW days. For metrics tracking, the external weather consultant provides BVES with the accounting of RFW days at a decimal level, to which BVES extends the calculation over its entire service territory OH circuit miles to determine the number of RFW days by circuit over the period.

> ***High Wind Warning overhead circuit mile days** – Detail the steps used to calculate the annual number of High Wind Warning (HWW) overhead circuit mile days. Calculate as the number of OH circuit miles that are under an HWW multiplied by the number of days those miles are under said HWW. Refer to High Wind Warnings as issued by the National Weather Service (NWS). For historical NWS data, refer to the Iowa State University archive of NWS watch / warnings.[35] Detail the steps used to determine if an OH circuit mile is under a HWW, providing an example of how the OH HWW circuit mile days are calculated for a HWW that occurred within the utility service territory over the last five years.*

The process for tracking High Wind Warning (HWW) days is a similar process to the previous response for RFW days, incorporating the same warning zones from the NWS. BVES provides its metrics analysis over the total OH system to account for the entire service territory.

When the NWS issues an RFW, they limit it by zones, typically by county. Given its compact service territory any RFW or HWW for BVES impacts all its circuit miles. In theory, BVES can run a spatial query on these zones to identify the total circuit mileage impacted by a RFW, but that is not necessary because it is known that all circuit miles are impacted. BVES measures the day by subtracting the RFW or HWW end date and time from the RFW or HWW start date and time to determine RFW circuit mile days. While BVES collects these statistics as directed, they are not particularly useful or insightful for BVES's system operations or performance beyond simply the NFDRS ratings and the RFW and HWW counts already tracked and supplied to the OEIS.

> ***Access and Functional Needs population** – Detail the steps to calculate the annual number of customers that are considered part of the Access and Functional Needs (AFN) population. Defined in Government*

[33] Energy Safety recommends using CalEnviroScreen and Senate Bill 535 to identify disadvantaged communities.
[34] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml
[35] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

Code § 8593.3 and D.19-05-042 as individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking,[36] *older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.*

BVES has determined its AFN customers to align with the following categories:

Customers enrolled in medical baseline and subsidy programs for low-income status;

Customers that have a preferred or native language other than English; and

Targeted customer accounts with self-identified statuses including, but not limited to, physical, developmental, or intellectual disabilities, chronic conditions with medical dependency, transportation-limited customers, senior adults and children, and pregnant women.

BVES reached out to mobile home parks located in its service area to ensure that mobile home park residents are being served correctly with regard to any medical baseline conditions. Most mobile home parks have master metered accounts and residents of these mobile home parks share a master electric bill included in the lease. This billing structure does not provide BVES any direct or relevant information about the resident medical conditions or situation. Accordingly, BVES increased its efforts to gather information about residents served behind-the-meter to assess whether they are medical baseline or AFN customers.

BVES also distributed an AFN flyer mailed to all residential customers on file to help determine whether any AFN person(s) is part of that household. This outreach effort helps establish a census of the AFN population, which is combined with data from medical baseline customers to allow emergency medical services teams, firefighters, and the sheriff's deputies to respond quickly during PSPS events and emergency situations. BVES has also coordinated with the fire department, city, and county agencies for assistance identifying AFN populations. To date, due to privacy issues, BVES has been unable to collect comprehensive data on AFN populations, but BVES is still pursuing its efforts.

4. ***Wildland-Urban Interface** – Detail the steps to calculate the annual number of circuit miles and customers in wildland-urban interface (WUI) territory. WUI is defined as the area where houses exist at more than 1 housing unit per 40 acres and (1) wildland vegetation covers more than 50% of the land area (intermix WUI) or (2) wildland vegetation covers less than 50% of the land area, but a large area (over 1,235 acres) covered with more than 75% wildland vegetation is within 1.5 mi (interface WUI) (Radeloff et al, 2005).*[37]

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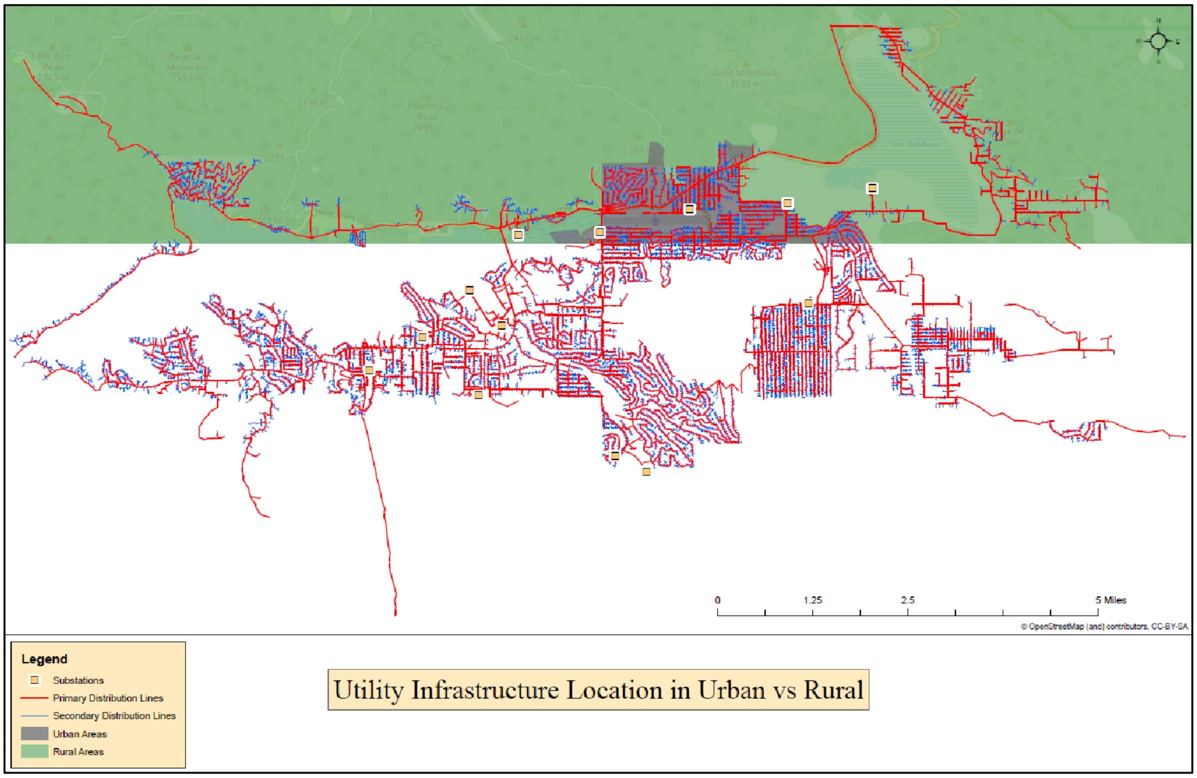
[36] Guidance on calculating number of households with limited or no English proficiency can be found in D.20-04- 003.

[37] Paper can be found here - https://www.fs.fed.us/pnw/pubs/journals/pnw_2005_radeloff001.pdf with the latest WUI map (form 2010) found here - http://silvis.forest.wisc.edu/data/wui-change/

Figure 4.5-9: Utility Infrastructure in Urban vs. Rural WUI Designations



5. ***Urban, rural, and highly rural*** *– Detail the steps for calculating the number of customers and circuit miles in utility territory that are in highly rural, rural, and urban regions for each year. Use the following definitions for classifying an area highly rural/rural/urban (also referenced in glossary):*

BVES recently updated its GIS mapping of its urban, rural, and WUI layers and identified that the service area and assets fall under a mix of urban and rural designations according to the U.S. Census Data. BVES is continuing to enhance its risk and asset maps and is working to graphically account for WUI designations under urban, rural, and highly rural. At this time, the majority of the service area is determined to be within the rural category. Tables 8, 9, and 10 of the QDR present unique characteristics of customer spread and utility infrastructure within these designations. A small extension of the Radford line, serving no customers, is currently assumed to be highly rural based on the mapping overlays, but may be revised due to calibration of coordinates at a future date.

> ***Highly rural*** *– In accordance with 38 CFR 17.701, "highly rural" must be defined as those areas with a population of less than 7 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*

Overlaying the WUI shapefile maps, the only area believed to be highly rural is along the Radford line that services no residential areas. BVES will increase the granularity of this designation in future QDRs.

> ***Rural*** *– In accordance with GO 165, "rural" must be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*

A portion of the BVES service territory resides in the rural WUI land designation accounting for the total customer account base.

> ***Urban*** *– In accordance with GO 165, "urban" must be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*

A small portion of BVES's customers is located in "urban" areas subject to the urban designation.

Population density numbers are calculated using the American Community Survey (ACS) 1-year estimates on population density by census tract for each corresponding year (2016 ACS 1-year estimate for 2016 metrics, 2017 ACS 1-year estimate for 2017 metrics, etc.). For years with no ACS 1-year estimate available, use the 1-year estimate immediately before the missing year (e.g., use 2019 estimate if 2020 estimate is not yet published, etc.)

4.6 Progress Reporting on Past Deficiencies

Report progress on all key areas of improvement identified in Section 1.3 of the utility's 2021 Action Statement. Provide a summary table of the actions taken to address these key areas and report on progress made over the year. Summarize the progress in a table using a high- level bullet point list of key actions, strategies, schedule, timeline for completion, quantifiable performance-metrics, measurable targets, etc. The table must also include a cross-referenced link to a more detailed narrative and substantiation of progress in an Appendix. The summary table must follow the format illustrated in Table 4.6-1.

Table 4.6-1: **Progress on Key Areas of Improvement and Remedies, 2021**

Utility-#	Issue Title	Summary of Progress
BVES- 21-01	Inadequate disaggregation of expenditure	Targets/Goals & Key Actions: Develop and use accounting methods to more accurately capture mitigation measures across multiple programs and projects as they correspond with risk reduction efforts of the 88 initiatives. *Completed Remedy Activities: 1; disaggregated expenditures and eliminated primary and secondary reference initiatives while provided unique cost spreading across applicable WMP initiative activities.* *Planned Remedy Activities: 1; continue to refine accounting mechanism as new WMP initiatives are added by the OEIS or existing initiatives are modified.* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: N/A - Complete* ***Refer to Appendix A Section A.1 for further details***
BVES- 21-02	Program targets are unmeasurable and difficult to track	Targets/Goals & Key Actions: BVES has been working to translate initiative targets into more quantitative assessments and value-based measurements to align with legacy tracking metrics. *Completed Remedy Activities: 3; BVES updated **Table 5.3-1** with a list of measurable targets for its activities, for which some have been modified. Additional 2021 progress activities are discussed in **Section 7.3**.* *Planned Remedy Activities: Going forward, BVES has modified its internal tracking documents to align with more measurable metrics for WMP initiative progress.* *Measurable Outcomes/Targets: **Table 5.3-1** revision is the resulting outcome.* *Schedule/Timeline for Completion: N/A - Complete* ***Refer to Appendix A Section A.2 for further details***
BVES- 21-03	Vegetation inspection roles lack minimum forestry and arboriculture qualifications	Targets/Goals & Key Actions: BVES requires its vegetation inspection contractors to maintain adequate evidence of qualified training. *Completed Remedy Activities: BVES provided OEIS evidence that its vegetation inspection personnel are adequately qualified and trained to perform inspection activities. This information was*

Utility-#	Issue Title	Summary of Progress
		communicated in the November 1, 2021, Progress Report. No additional descriptions are required as an update. *Planned Remedy Activities: N/A - Complete* *Measurable Outcomes/Targets: Specific certification descriptions per vegetation management personnel* *Schedule/Timeline for Completion: N/A - Complete* ***Refer to Appendix A Section A.3 for further details***
BVES- 21-04	No climate driven risk mapping	Targets/Goals & Key Actions: BVES now has and uses climate-driven risk mapping. *Completed Remedy Activities: 1; BVES contracted with a fire modeling firm to develop probability and consequence maps for current and future conditions to aid in informing future WMP initiative planning.* *Planned Remedy Activities: BVES plans to contract with an additional firm in 2022 to develop real-time modeling capabilities for enhanced conditional awareness.* *Measurable Outcomes/Targets: 1; The resulting maps presented in* ***Section 4.5.1*** *illustrate the fire risk in BVES's service area.* *Schedule/Timeline for Completion: BVES plans to contract with an additional contractor for real-time analysis modeling in mid-2022* ***Refer to Appendix A Section A.4 for further details***
BVES- 21-05	Lack of consistency in approach to wildfire risk modeling across utilities	Targets/Goals & Key Actions: BVES participates in the OEIS Risk Mapping Working Group, which commenced in early October 2021. Part of the initial conversations centered around understanding each of the investor-owned utility (IOU) methodologies for demonstrating risk assessment approaches, as well as current modeling techniques and data elements embedded within those models. BVES will be employing Technosylva to create more uniform risk modeling in alignment with other IOUs. *Completed Remedy Activities: N/A* *Planned Remedy Activities: BVES plans to contract with an additional firm in 2022 to develop real-time modeling capabilities for enhanced conditional awareness.* *Measurable Outcomes/Targets: N/A*

Utility-#	Issue Title	Summary of Progress
		Schedule/Timeline for Completion: BVES plans to contract with an additional contractor for real-time analysis modeling in mid-2022 ***Refer to Appendix A Section A.5 for further details***
BVES- 21-06	Disparities between BVES's situational awareness, forecasting capabilities, and maturity model reporting	Targets/Goals & Key Actions: BVES provided the OEIS additional details about how it arrives at its maturity assessment ratings for situational awareness and forecasting within the November 1, 2021 Progress Report *Completed Remedy Activities: BVES detailed its process for determining on collecting and measuring physical impacts of weather on its grid, with more detail provided in **Appendix A Section A.6.*** *Planned Remedy Activities: 4* *Measurable Outcomes/Targets: 4* *Schedule/Timeline for Completion: BVES proposes to complete additional actions that will give more complete and detailed weather and system information by the end of 2023.* ***Refer to Appendix A Section A.6 for further details***
BVES- 21-07	Lack of detail on prioritization of initiatives based on determined risk	Targets/Goals & Key Actions: BVES added additional detail to describe the risk register, risk-based decision-making methodology, and the Fire Safety Circuit Matrix and how those tools are used to prioritize wildfire mitigation activities. This is described in detail in ***Section 4.5.1***. BVES further describes how these tools have evolved to incorporate the climate risk mapping from REAX Engineering and will incorporate the mapping and modeling to be performed by Technosylva. Finally, BVES is looking at providing more granular information, that identifies higher risk areas within each circuit. *Completed Remedy Activities: 1; updated the risk register and fire safety circuit matrix to present high risk circuits and a 10-year outlook on risk profile as mitigations are implemented.* *Planned Remedy Activities: N/A* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: BVES plans to incorporate the additional mapping/modeling data in the 2023 WMP and will continue to improve its risk tools annually.* ***Refer to Appendix A Section A.7 for further details***

Utility-#	Issue Title	Summary of Progress
BVES- 21-08	Limited evidence to support the effectiveness of covered conductor	<u>Targets/Goals & Key Actions:</u> BVES has investigated methods to capture the risk reduction and cost-effectiveness across California and North America through internal engineering reviews, external consultant support, and ongoing discussions with the IOUs. As part of this effort, BVES participates in the covered conductor working group with other California IOUs as initiated by the OEIS. Available evidence suggests that covered conductor is effective at reducing fire ignition risk thereby reducing the need for PSPS activation. *Completed Remedy Activities: Ongoing evaluation of covered conductor hardening and its alternatives* *Planned Remedy Activities: BVES's covered conductor approach is suitable for its risk profile and service territory needs. BVES will continue evaluating as the working group produces more insight from other IOU demonstrations.* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: N/A* ***Refer to Appendix A Section A.8 for further details***
BVES- 21-09	Lack of asset inspection quality assurance and quality control (QA/QC) program.	<u>Targets/Goals & Key Actions:</u> BVES monitors all aspects of inspection execution including work verification performed through third-party contractors on an annual basis. This includes a formal QA/QC program established in 2021 with full implementation in 2022. *Completed Remedy Activities: 3; preliminary QA/QC documentation has been generated and corresponded to Energy Safety as part of the November 1, 2021 Progress Report* *Planned Remedy Activities: 2; BVES has formalized a vegetation management QA/QC process and issued a similar process for electrical equipment inspections at the end of 2021.* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: 2022 and ongoing* ***Refer to Appendix A Section A.9 for further details***
BVES- 21-10	Limited discussion of community outreach	<u>Targets/Goals & Key Actions:</u> BVES maintains a robust community outreach program. BVES has posted a training video on its website to demonstrate the activities performed within the utility's vegetation management program. BVES utilizes social media, bill inserts, communication emails, community workshop discussions, and radio advertisements to alert customers of vegetation management activities as well as general WMP related initiatives and possible PSPS risk during fire season. Additionally, weekly updates on tree trimming crew locations are provided on BVES's public

Utility-#	Issue Title	Summary of Progress
		website. BVES also provides a direct line for customers to call with questions and maintains a list of frequently asked questions and their answers to support community awareness. *Completed Remedy Activities: BVES provided Energy Safety example notifications and communication methods related to vegetation management activities in the November 1, 2021 Progress Report.* *Planned Remedy Activities: NA--Completed* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.10 for further details***
BVES- 21-11	Inadequate discussion of QA/QC of VM inspections	Targets/Goals & Key Actions: BVES has expanded its discussion of QA/QC activities of vegetation management inspections in this WMP at **Section 7.3.5.13**. This includes descriptions of lessons learned from third-party evaluations and inspections, providing the number of QA/QC evaluation and inspections completed each year, providing a QA/QC audit target as a percentage of total VM inspections per year, explaining the difference between the BVES QA and QC programs, and reporting on BVES's plan to add a QA program. *Completed Remedy Activities: BVES provided an update of the number of QA/QC evaluation and inspections completed year over year.* *Planned Remedy Activities: Ongoing activity to account for QA/QC audit targets* *Measurable Outcomes/Targets: BVES targets 72 vegetation management QC checks per year. This is about 15 percent of the service area.* *Schedule/Timeline for Completion: Ongoing activity* ***Refer to Appendix A Section A.11 for further details***
BVES- 21-12	***Spatial data issues***	
BVES- 21-12-1	Empty/null geometry	Targets/Goals & Key Actions: BVES has added the attributes required by the Energy Safety GIS Data reporting standard. The GIS data submitted on a quarterly basis now includes this information. *Completed Remedy Activities: Q4 2021 has the correct geometry and attributes.* *Planned Remedy Activities: Moving forward features will have geometry and attributes.*

Utility-#	Issue Title	Summary of Progress
		Measurable Outcomes/Targets: Last submittal met the standard. *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-2	OH and UG conductors separated	Targets/Goals & Key Actions: BVES now reports the overhead and underground conductor data together as required by the Energy Safety GIS Data reporting standard. The GIS data submitted on a quarterly basis now includes this information. *Completed Remedy Activities: Q4 2021 Overhead and Underground were in the same feature class, within the GDB template for Q4 2021 data.* *Planned Remedy Activities: Moving forward both Overhead and Underground lines will be in the same line feature.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-3	Non-unique primary keys	Targets/Goals & Key Actions: BVES now includes unique primary keys ID fields. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: Unique ID have been added to all submitted Q4 data.* *Planned Remedy Activities: Fields will be checked to assure Unique IDs are populated.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-4	Missing foreign keys	Targets/Goals & Key Actions: BVES now includes the foreign keys in the VM outages feature class as required by the Energy Safety GIS Data reporting standard. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: VM outages now have "DoutageID" field.* *Planned Remedy Activities: Fields will be checked to assure "DoutageID" is populated.*

Utility-#	Issue Title	Summary of Progress
		Measurable Outcomes/Targets: Last submittal met the standard. *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-5	Domain values not used	Targets/Goals & Key Actions: BVES now uses coded domain values as required by the Energy Safety GIS Data reporting standard. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: OEIS's GIS GDB file template was used, which has resolved the issues.* *Planned Remedy Activities: Using the GDB template will avoid this issue moving forward.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-6	Changed field names	Targets/Goals & Key Actions: BVES now uses feature class and field names as required by the Energy Safety GIS Data reporting standard. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: OEIS's GIS GDB file template was used, which has resolved the issues.* *Planned Remedy Activities: Using the GDB template will avoid this issue moving forward.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-12-7	Removed fields	Targets/Goals & Key Actions: BVES no longer removes fields from the geodatabase template. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: OEIS's GIS GDB file template was used, which has resolved the issues.* *Planned Remedy Activities: Using the GDB template will avoid this issue moving forward.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed*

Utility-#	Issue Title	Summary of Progress
		Refer to Appendix A Section A.12 for further details
BVES- 21-12-8	Changed field type or length	Targets/Goals & Key Actions: BVES no longer modifies the length or data type of fields in the geodatabase template. The GIS data submitted in the Q3 2021 QDR spatial data submission and beyond now includes this information. *Completed Remedy Activities: OEIS's GIS GDB file template was used, which has resolved the issues.* *Planned Remedy Activities: Using the GDB template will avoid this issue moving forward.* *Measurable Outcomes/Targets: Last submittal met the standard.* *Schedule/Timeline for Completion: N/A--Completed* ***Refer to Appendix A Section A.12 for further details***
BVES- 21-13	Unexplained changes to risk spend efficiency (RSE) estimates for wildfire and PSPS mitigation initiatives	Targets/Goals & Key Actions: There are two components to RSE estimates: (1) risk reduction estimate and (2) annualized cost estimate. The changes in RSE values were almost exclusively due to updating the annualized cost data for each initiative. Each year, BVES reviews and updates cost estimates for WMP initiative to ensure it is reflective of the market (including adjustments for inflation) and any changes to the details of the project scope. BVES also re-evaluates the risk benefit as well each year. *Completed Remedy Activities: BVES updated the RSE estimates for wildfire and PSPS activities, as presented in **Figure 4.2-2** and **Figure 4.2-3**.* *Planned Remedy Activities: BVES will continue to update RSE estimates for ongoing reporting* *Measurable Outcomes/Targets: Updated RSE values* *Schedule/Timeline for Completion: N/A—Complete* ***Refer to Appendix A Section A.13 for further details***
BVES- 21-14	Limited discussion on reduction of scale, scope, and frequency of PSPS	Targets/Goals & Key Actions: The appearance of limited discussion on BVES's near-term progress for reduction of scale, scope, and frequency of PSPS has been inherently tied to lack of any activation of PSPS events since the protocols were formally defined through Rulemaking 18-12-005. Additionally, BVES more thoroughly developed its PSPS protocols in 2021 further reducing the very low likelihood of the activation of any significant PSPS in the BVES service territory.

Utility-#	Issue Title	Summary of Progress
		Completed Remedy Activities: BVES provided discussion into reduction of scale, scope, and frequency of potential PSPS activations to Energy Safety in the November 1, 2021 Progress Report. *Planned Remedy Activities: BVES will be enhancing its PSPS protocol and plans as a result of implementing real-time fire risk modeling in mid-late 2022 and to align with Phase 3 guidelines of PSPS activation standards.* *Measurable Outcomes/Targets: N/A* *Schedule/Timeline for Completion: Ongoing through 2022* ***Refer to Appendix A Section A.14 for further details***

5 INPUTS TO THE PLAN AND DIRECTIONAL VISION FOR WMP

5.1 Goal of Wildfire Mitigation Plan

The goal of the WMPs is shared across Energy Safety and all utilities: Documented reductions in the number of ignitions caused by utility actions or equipment and minimization of the societal consequences (with specific consideration to the impact on AFN populations and marginalized communities) of both wildfires and the mitigations employed to reduce them, including PSPS.

The following sub-sections report utility-specific objectives and program targets towards the WMP goal. No utility response is required for Section 5.1.

5.2 The Objectives of the Plan

Objectives are unique to the utility and reflect the 1, 3, and 10-year projections of progress towards WMP goals. Objectives are determined by the portfolio of mitigation strategies proposed in the WMP. The objectives of the plan must, at a minimum, be consistent with the requirements of California Pub. Util. Code §8386(a) – Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment

Describe utility WMP objectives, categorized by each of the following timeframes, highlighting changes since the prior WMP report:

1. *Before the next Annual WMP Update*
2. *Within the next 3 years*
3. *Within the next 10 years – long-term planning beyond the 3-year cycle*

The primary objective of the WMP is to ensure that BVES constructs, maintains, and operates its electric lines and equipment in a manner that minimizes the risk of catastrophic wildfire posed by its lines and equipment. Additionally, the WMP helps to ensure BVES is compliant with all applicable regulations and statutes. Finally, an objective of the WMP is to assist BVES in its goal to continue to provide customers with safe delivery of service at competitive rates and maintain its role as a valued partner in the community it serves by promoting public safety.

BVES's WMP aims to reduce threats of utility-caused wildfires by eliminating sources of ignition and, in the event of a wildfire affecting the BVES service area, to provide emergency response and restoration actions regardless of cause. Another objective of BVES's WMP is to minimize the need to activate PSPS events. Through its WMP, BVES seeks to fulfill the requirements detailed in PUC Section 8386 and associated statutes by identifying wildfire risks and risk drivers within the BVES service territory; providing an overview of strategies, protocols, plans, and programs to mitigate wildfires; tracking metrics to monitor performance of the WMP's initiatives; ensuring the performance of quality control and assurances of completed work; and setting forth protocols for communicating with customers and public-safety partners throughout wildfire mitigation, PSPS, and emergency events.

BVES identifies its objectives as categorized by timeframe: objectives to accomplish before the next annual WMP update, within the next three years, and within the next ten years.

Objectives before the next Annual WMP Update

Over the course of 2022, the primary objective of BVES is to continue to reduce wildfire risks through the execution of its grid hardening initiatives, risk assessment and prioritization, and leveraging situational awareness and weather monitoring on a more regular basis. BVES will continue to replace bare wire with covered wire in the highest risk areas and harden all of the main evacuation routes. Regarding situational awareness, these goals include continued improvement through BVES's contracted meteorologist, Technosylva near-real-time fire risk assessment applications and weather stations, improving coordination and communication with stakeholders, employing forecasting capabilities through fire predictive live models, and continuing aggressive vegetation management and inspection. BVES also plans to continue to enhance its data collection and handling. BVES will continue to improve its workforce readiness through recruitment, training, and the strategic use of consultants to supplement BVES staff.

Objectives within the next 3 years

The three-year objectives include the annual WMP update objectives with the additional grid hardening efforts, increased situational awareness and control improvements expected from completion of the grid automation initiatives, real-time fire risk modeling, and increased resiliency to serve load via local generation through potential solar and storage projects. BVES expects to make substantial progress in replacing all sub-transmission bare wire with covered wire. BVES will also begin to harden secondary evacuation routes throughout the service area.

Objectives within the next 10 years

The ten-year objectives include significant reduction of wildfire ignition probability and improved system resilience. Much of this will stem from BVES's grid hardening efforts. BVES should also fully realize the benefits from its various grid automation initiatives and its proposed solar and storage projects. BVES's long-term grid hardening will be aimed at continuing to replace bare wire with covered wire on its sub-transmission and distribution systems. This project will continue over the next ten years prioritizing the highest risk circuits first. Additionally, in the next ten years, BVES will look to leverage the fiber network installed in its service area with new technologies in monitoring equipment, systems, and external conditions and bringing this data to databases to be utilized in risk determination (perhaps real-time) and to improve situational awareness of operational staff. Specific technologies and sensors will be considered over the next few years and may be included in future WMPs if warranted. BVES will also work to continue automating switches and equipment where feasible and beneficial to mitigate wildfire risk.

5.3 Plan Program Targets

Program targets are quantifiable measurements of activity identified in WMPs and subsequent updates used to show progress towards reaching the objectives.

List and describe all program targets the electrical corporation uses to track utility WMP implementation and utility performance over the last five years. For all program targets, list the 2019 to 2021 performance, a numeric target value that is the projected target for end of year 2022 and 2023, units on the metrics reported, the assumptions that underlie the use of those metrics, update frequency, and how the performance reported could be validated by third parties outside each utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each targeted preventive strategy and program.

Pub. Util. Code Section 8386.3(c)(5) requires a utility to notify Energy Safety "after it completes a substantial portion of the vegetation management (VM) requirements in its wildfire mitigation plan." To ensure compliance with this statue, the utility is required to populate Table 5.3-1 with VM program targets that the *utility can determine when it has completed a "substantial portion"[38] and that Energy Safety can subsequently audit. Energy Safety has provided some required, standardized VM targets below. It is expected that the utilities provide additional VM targets beyond those required. The identification of other VM targets and units for those targets (e.g., for inspections, customer outreach, enhanced vegetation management, etc.) are at the discretion of the utility.*

Additionally, in Table 5.3-1, utilities must populate the column "Target%/ Top-Risk%" for each 2022 performance target related to initiatives in the following categories: Grid design and system hardening; Asset management and inspections; and Vegetation management and inspections. This column allows utilities to identify the percentage of the target that will occur in the highest risk areas. For example, if a utility targets conducting 85% of its vegetation management program in the top 20% of its risk-areas, it should input "85/20" in this column. In the "Notes" column, utilities must provide definitions and sources for each of the "Top-Risk%" values provided. In the given example above, an acceptable response would be: "The top 20% of risk areas used for this target relate to the circuit segment risk rankings from [Utility Company's] Wildfire Risk Model outputs, as described in [hyperlink to Section XX] of the 2022 WMP Update."

[38] Energy Safety intends to define "substantial portion" in its forthcoming Compliance Guidelines. This definition may be included in the Final version of the 2022 WMP Update Guidelines.

Table 5.3-1: List and description of program targets, last 5 years

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
Weather Station Installation Program	10	10	8	8	2	2	N/A	N/A	# of Weather Stations Installed	Yes for 2020	
ALERTWildfire Camera Installation Program	N/A	N/A	2	2	2	4	N/A	N/A	# of HD Cameras Installed	Yes for 2020	
Situational Awareness Hardware Program // Fault Indicator Installation Project	N/A	N/A	N/A	N/A	N/A	N/A	50	N/A	# of FIs Installed	NA	
Covered Conductor Project - (4kV & 34.5 kV Systems)(7.3.3.3.1 & 7.3.3.3.2)	0.5	0.5	4.3	7.8	12.9	12.3	12.9	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Fuse Replacement Program	600	283	1700	2001	805	901	N/A	100 / 100	# of Expulsion fuses replaced	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
Pole Loading Assessment & Remediation Program	350	371	215	243	200	223	165	100 / 100	# of Poles Replaced or Remediated	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Detailed Inspection Program	100	118.6	40	45.9	50	54.9	29	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Infrared Inspection Program	NA	NA	NA	NA	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
UAV HD Photography/Videography Inspection Program	NA	NA	NA	NA	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
											performance within 100% of the top risk area.
Pole Loading Assessment & Remediation Program // Intrusive Pole Inspection Activities	1500	1588	190	191	500	557	225	100 / 100	# of Poles assessed for loading criteria	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Intrusive Pole Inspection Program	0	48	0	0	850	876	850	100 / 100	# of Poles intrusively inspected	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
LiDAR Inspection Program	211	211	211	211	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
Third Party Ground Patrol (7.3.4.9.1)	211	211	211	211	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Ground Patrol Inspection Program	211	211	211	211	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Inspection Improvement Activities // QA/QC Activities	NA	NA	NA	NA	NA	2	4	100 / 100	# of VM Audits	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Substation Inspection Program	144	144	144	144	144	144	144	100 / 100	# of Substations Inspected	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
											performance within 100% of the top risk area.
Enhanced Vegetation Management Program // Detailed Inspections	100	118.6	40	45.9	50	54.9	29	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Inspection Improvement Activities // QA/QC Activities	30	45	30	31	72	112	72	100 / 100	# of VM QCs	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
3rd Party Ground Patrol (7.3.5.9.1)	211	211	211	211	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
Enhanced Vegetation Management Program // Patrol Inspections	211	211	211	211	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Enhanced Vegetation Management Program // Hazardous Tree Removal	100	123	100	128	120	157	88	100 / 100	# of Trees Removed	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Substation Inspection Program // Vegetation Management	144	144	144	144	144	144	144	100 / 100	# of Substations Inspected	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Enhanced Vegetation Management Program // Equipment Vegetation Clearances	NA	NA	NA	NA	NA	NA	72	100 / 100	Circuit Miles	No	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
											performance within 100% of the top risk area.
Community Outreach Program	NA	NA	NA	NA	360	422	360	N/A	# of Community Engagement Events	No	
Covered Conductor Project - Radford Line	NA	NA	NA	NA	NA	NA	2.7	100 / 100	Circuit Miles	No	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Covered Conductor Project - Radford Line (7.3.3.3.3)	NA	NA	NA	NA	NA	NA	70	100 / 100	# of Poles Hardened	No	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Evacuation Route Hardening Program (Pilot)	NA	NA	5	5	5	5	NA	100 / 100	# of Poles Hardened Along Evacuation Route	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the

Program target	2019		2020		2021		2022		Units	Audited by Third-party? (Y/N)	Notes (Including definitions and sources for Top-Risk%)
	Target	Perf.	Target	Perf.	Target	Perf.	Target	Target%/ Top-Risk%			
											performance within 100% of the top risk area.
Evacuation Route Hardening Program	NA	NA	NA	NA	400	400	412	100 / 100	# of Poles Hardened Along Evacuation Route	No	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
Tree Attachment Removal Program	50	43	200	214	70	74	80	100 / 100	# of Tree Attachments Removed	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.
UAV HD Photography/Videography Inspection Program	NA	NA	NA	NA	211	211	211	100 / 100	Circuit Miles	Yes for 2020	BVES's service area is nearly entirely Tier 2 with a small portion in Tier 3. BVES measures the Target%/Top-Risk% for grid hardening, asset and vegetation inspection and management activities as 100% of the performance within 100% of the top risk area.

5.4 Planning for Workforce and Other Limited Resources

Report on worker qualifications and training practices regarding wildfire and PSPS mitigation for workers in the following target roles:

Vegetation inspections

Vegetation management projects

Asset inspections

Grid hardening

Risk event inspection

For each of the target roles listed above:

List all worker titles relevant to target role (target roles listed above)

For each worker title, list and explain minimum qualifications with an emphasis on qualifications relevant to wildfire and PSPS mitigation. Note if the job requirements include the following:

> *Going beyond a basic knowledge of General Order 95 requirements to perform relevant types of inspections or activities in the target role*
>
> *Being a "Qualified Electrical Worker" (QEW) and define what certifications, qualifications, experience, etc. is required to be a QEW for the target role for the utility.*
>
> *Include special certification requirements such as being an International Society of Arboriculture (ISA) Certified Arborist with specialty certification as a Utility Specialist*

Report percentage of Full Time Employees (FTEs) in target role with specific job title

Provide a summarized report detailing the overall percentage of FTEs with qualifications listed in (2) for each of the target roles.

> *Report plans to improve qualifications of workers relevant to wildfire and PSPS mitigation. The utility must explain how they are developing more robust outreach and onboarding training programs for new electric workers to identify hazards that could ignite wildfires.*

Minimum Qualifications & Plans for Resource Sufficiency

Successful implementation of the WMP requires adequate staffing. BVES uses a combination of in-house and contract resources. Program owners are described in **Section 1**. BVES hired additional resources to fill identified roles for the WMP's implementation over the course of 2020 and 2021. The utility also contracted with a qualified forester and plans to continue contracting with inspectors to provide additional resources to carry out projects and programs identified in this WMP. BVES also relies upon existing mutual aid agreements with public safety partners for emergency events. The following describes the additional resources recently added for ongoing WMP implementation within the next WMP term:

Wildfire Mitigation and Reliability Engineer – Oversees wildfire mitigation initiatives by collecting and analyzing a comprehensive set of data and metrics and serves as the company liaison for first responders and public safety partners. *(Secured in 2020.)*

Project Coordinator – Manages schedule, logistics, labor resources, and budget to achieve WMP project implementation and provides periodic project progress updates. *(Secured in 2020.)*

Inspectors – Inspects overhead lines and equipment to comply with GOs 165 and 174 inspection requirements, GO 95 and 128 construction standards, the National Electrical Safety Code (NESC) and other related industry standards and codes. (*Contracted since 2020.*)

Forester – Provides field support and oversight of high-risk vegetation management work. The contractor will be knowledgeable of and comply with applicable rules and regulations (e.g., GO 95 and Public Resources Code 4293) with formal training in forest management as well as a relevant degree. (*Contracted in 2020 and started in 2021*).

GIS & Risk Impact Modeling – Develops the basis for a data repository and managed architecture that will help drive BVES alignment to the data schema framework. The contractor will apply the GIS gap and data analysis results to inform the development of an updated risk model that looks at wildfire, public safety and PSPS impact risk factors. The GIS contractor also trains the in-house GIS professional to assist BVES to build more GIS capabilities. (*Contracted in 2021*).

Recruiting and Training Personnel

BVES uses a combination of permanent and contract personnel. Over the last year, BVES updated responsibilities of existing positions and identified the need for additional positions for ongoing WMP support. BVES conducts training based on job duties on an as needed basis, meeting or exceeding all minimum regulatory requirements.

> BVES outsources all vegetation management and the contractor BVES uses has no projected shortfalls in staffing. Under this arrangement, all BVES's vegetation management personnel are qualified and extensively trained.
>
> BVES has re-instituted its lineman apprenticeship program that had been dormant. BVES has three apprentices at varying levels of progress working toward journeyman lineman qualifications. The apprenticeship process takes approximately 3 years.
>
> BVES recently established a relocation policy to relocate new hires from out of state to increase the talent sourcing pool. Because of BVES's remote location, employees must live in the service territory. BVES screens candidates initially through remote interviews using online collaboration tools. Candidates that are favorably screened are brought to Big Bear Lake for in-person assessment and service territory orientation.
>
> BVES uses a local temporary staffing agency to source local talent for certain positions, for example project coordinators and skilled accountants for work order documentation and processing.
>
> BVES prefers to hire experienced personnel but has improved its capabilities and willingness to train new staff that demonstrate strong potential for success to the specifics of utility skillsets. BVES keeps a monthly headcount and is developing the requested metrics as our recruiting and apprenticeship programs mature, including from out of state and other California utilities.

5.4.1 Target Role: Vegetation Inspections

Worker titles in target role

Minimum qualifications

FTE percentages by title in target role

Percent of FTEs by high-interest qualification

Plans to improve worker qualifications

Table 5.4-1: Vegetation Inspections Qualifications

Target Role: Vegetation Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	Bachelor's Degree in an engineering field or a technical discipline required. Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred. Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application.	Professional Engineer license in California required. If not held, must obtain within 2 years of employment.	100%	100%	None required
Wildfire Mitigation and Reliability Engineer (BVES Employee)	Bachelor of Science degree in Engineering, Mathematics, Physics, or other related technical discipline. Prior electric utility experience preferred. Understanding of statistical analysis and probabilistic methods preferred. Prior experience working with Enterprise Resource Planning (ERP) software or asset management software, Oracle based accounting systems, Outage Management Systems, Geographic Information Systems (GIS) and SCADA systems preferred.	N/A	100%	100%	None required
Field Inspector (BVES Employee)	Three years of Journeyman Lineman or above experience. Experience inspecting overhead and underground facilities. Class C California Driver's License	IBEW Journeyman Lineman status in good standing Demonstrated knowledge and proficiency in GO 95, GO 128, and GO 165 requirements.	100%	100%	None required

Target Role: Vegetation Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Utility Systems Specialist Inspector/Lead Inspector (Contractor)	Overhead Distribution and/or Transmission distribution inspection experience (2-year min) Identification of all overhead equipment Current Driver License Computer and GIS mapping experience	NESC and ANSI Inspection experience (1-year min) Red Cross FA/CPR certified Wildfire Training	100%	100%	None required
Geospatial Project Manager (Contractor)	8 years of GIS and Remote Sensing Experience 5 years or more in a Supervisory Role Advanced Knowledge of LiDAR Sensors and Data Advanced GIS Skills and Problem Solving	Geospatial Information Systems Professional (GISP)	100%	100%	ASPRS Certified Mapping Scientist, LiDAR
Geospatial Lead Analyst (Contractor)	8 years of GIS and Remote Sensing Experience Strong Quality Control and Detail Advanced Knowledge of LiDAR Sensors and Data Advanced GIS Skills and Problem Solving	N/A	100%	N/A	ASPRS Certified Remote Sensing Technologist
Geospatial Technician (Contractor)	Solid Understand of GIS and Remote Sensing Science Strong Attention to Detail Strong Computer Skills Work Independently	N/A	100%	N/A	None required

5.4.2 Target Role: Vegetation Management Projects

1. Worker titles in target role

2. Minimum qualifications

3. FTE percentages by title in target role

4. Percent of FTEs by high-interest qualification

5. Plans to improve worker qualifications

Table 5.4-2: Vegetation Management Projects

Target Role: Vegetation Management Projects					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Tree Trim General Foreman/Supervisor (Contractor)	5 years of line clearance tree pruning experience in a Foreman role	ISA Certification	100%	100%	None required

	Line clearance Certification Current California Driver License General Computer knowledge	Line-clearance qualified tree-trimmer			
Tree Trimmer (Contractor)	Strong work ethic Current California Driver License (Class B permit) General computer skills	ISA Certification Line-clearance qualified tree-trimmer	100%	100%	None required

5.4.3 Target Role: Asset Inspections

1. *Worker titles in target role*
2. *Minimum qualifications*
3. *FTE percentages by title in target role*
4. *Percent of FTEs by high-interest qualification*
5. *Plans to improve worker qualifications*

Table 5.4-3: Asset Inspections

Target Role: Asset Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Field Inspector (BVES Employee)	Three years of Journeyman Lineman or above experience. IBEW Journeyman Lineman status in good standing Demonstrated knowledge and proficiency in GO 95 and GO 128. Experience inspecting overhead and underground facilities. Class C California Driver's License	Journeyman Lineman	100%	100%	None required
Light Crew Foreman (BVES Employee)	Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances. Occupational hazards and standard safety precautions necessary in work.	Journeyman Lineman	100%	100%	None required

Target Role: Asset Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
	Class A California Driver's License.				
Service Crew Foreman (BVES Employee)	Three years of experience at the journey level in construction, maintenance, and repair of both overhead and underground electrical systems. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances. Inspection program requirements of GO 165 and GO 174. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.	Journeyman Lineman	100%	100%	None required
Substation Technician (BVES Employee)	Minimum five (5) years' experience observing and operating substation equipment. Journeyman Lineman certification a plus. Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals. Class C California Driver License. Sound knowledge of: Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work. Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV). Inspection program requirements of GO 174. SCADA and electric utility GIS systems. IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment	N/A	100%	N/A	None required

Target Role: Asset Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Utility Systems Specialist Inspector/Lead Inspector (Contractor)	Overhead Distribution and/or Transmission distribution inspection experience (2-year min) Identification of all overhead equipment Current Driver License Computer and GIS mapping experience	NESC and ANSI Inspection experience (1-year min) Red Cross FA/CPR Certified Wildfire Training	100%	100%	None required
Geospatial Project Manager (Contractor)	8 years of GIS and Remote Sensing Experience 5 years or more in a Supervisory Role Advanced Knowledge of LiDAR Sensors and Data Advanced GIS Skills and Problem Solving	Geospatial Information Systems Professional (GISP)	100%	100%	ASPRS Certified Mapping Scientist, LiDAR
Geospatial Lead Analyst (Contractor)	8 years of GIS and Remote Sensing Experience Strong Quality Control and Detail Advanced Knowledge of LiDAR Sensors and Data Advanced GIS Skills and Problem Solving	N/A	100%	N/A	ASPRS Certified Remote Sensing Technologist
Geospatial Technician (Contractor)	Solid Understand of GIS and Remote Sensing Science Strong Attention to Detail Strong Computer Skills Work Independently	N/A	100%	N/A	None required

5.4.4 Target Role: Grid Hardening

1. Worker titles in target role

2. Minimum qualifications

3. FTE percentages by title in target role

4. Percent of FTEs by high-interest qualification

5. Plans to improve worker qualifications

Table 5.4-4: Grid Hardening

Target Role: Grid Hardening					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	Bachelor's Degree in an engineering field or a technical discipline required. Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred. Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application.	Professional Engineer license in California required. If not held, must obtain within 2 years of employment.	100%	100%	None required
Field Operations Supervisor (BVES Employee)	Associate degree (Bachelor's preferred) in electrical engineering and construction management or related field or fifteen (15) years of experience in supervising line operations. Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required Thorough knowledge of GO 95/165 and Construction Methods	N/A	100%	N/A	None required
Regulatory Compliance Project Engineer (BVES Employee)	Bachelor's Degree in Electrical Engineering, or related field. Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable. Excellent knowledge and strong experience in working in a highly regulated environment and working with a large number of agencies such as: US Forest Service, US Bureau of Land Management, US Fish and Wildlife Service, California Department of Fish and Game, California Division of Occupational Safety and Health (DOSH, also known as Cal/OSHA), California Department of Transportation (Caltrans), Department of Transportation (DOT), State Water	Professional Engineer's (PE) license in the California is strongly desired. Note, that if the applicant does not have a PE in California, the applicant will be required to obtain a California PE license within 12 months of employment	50%	100%	None required

Target Role: Grid Hardening					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
	Resource Control Board, California Environmental Protection Agency (EPA), and South Coast Air Quality Management District (SCAQMD). Experience with California Environmental Quality Act (CEQA) process. Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174.	at BVES, Inc. in this position.			
Project Coordinator (BVES Employee)	Associates or bachelor's degree preferred Project Management course work and Project Management Professional (PMP) certification preferred Four years of experience in construction projects including demonstrable project management experience	N/A	100%	N/A	None required
Utility Planner I (BVES Employee)	Bachelor's degree in Engineering or successful completion of a Utility Planning Certification required. Minimum of 2 years utility or comparable construction planning experience performing duties such as estimating, planning, and electrical distribution design work.	N/A	100%	N/A	None required
Engineering Inspector	Minimum three years of experience at an Engineering Technical position or equivalent in an electric utility working the area of distribution. Experience identifying in field electrical equipment. Experience in distribution facility overhead design. Demonstrated Experience in AutoCAD design software and experience with GIS software (desired). Excellent understanding of the JPA process and paperwork	N/A	100%	N/A	None
Light Crew Foreman (BVES Employee)	Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable	Journeyman Lineman	100%	100%	None required

Target Role: Grid Hardening					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
	codes, accident prevention rules and ordinances. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.				
Service Crew Foreman (BVES Employee)	Three years of experience at the journey level in construction, maintenance, and repair of both overhead and underground electrical systems. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances. Inspection program requirements of GO 165 and GO 174. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.	Journeyman Lineman	100%	100%	None required
Lineman (BVES Employee)	Certified completion of a union or company recognized lineman apprenticeship training program. IBEW Journeyman Lineman status in good standing. Past experience in climbing wooden power poles and working on high voltage power lines. Knowledge of basic principles of electricity, current theory mathematics, GO 95 and 128 and all applicable codes, accident prevention orders and ordinances. Knowledge of methods, material and tools used in the construction, maintenance and repair of an overhead/underground transmission, distribution, and substation electrical system Must possess or obtain within 6 months a valid Class A California Driver's License.	Journeyman Lineman	80%	100%	None required
Substation Technician (BVES Employee)	Minimum five (5) years' experience observing and operating substation equipment.	N/A	100%	N/A	None required

Target Role: Grid Hardening					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
	Journeyman Lineman certification a plus. Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals. Sound knowledge of: IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment. Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work. Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV). Inspection program requirements of GO 174. SCADA and electric utility GIS systems. Class C California Driver License.				

5.4.5 Target Role: Risk Event Inspections

1. *Worker titles in target role*
2. *Minimum qualifications*
3. *FTE percentages by title in target role*
4. *Percent of FTEs by high-interest qualification*
5. *Plans to improve worker qualifications*

Table 5.4-5: Risk Event Inspections

Target Role: Risk Event Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	Bachelor's Degree in an engineering field or a technical discipline required. Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and	Professional Engineer license in California required. If not held, must obtain within 2 years of employment.	100%	100%	None required

Target Role: Risk Event Inspections					
Worker Titles *(1)*	**Minimum Qualification** *(2)*	**Special Certification Requirements** *(2a, b, c)*	**Percent FTE in Target Role** *(3)*	**Percent of FTEs by High-Interest Qualification** *(4)*	**Plans to Improve Qualifications** *(5)*
	knowledge of regulatory processes preferred. Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application.				
Field Operations Supervisor (BVES Employee)	Associate degree (Bachelor's preferred) in electrical engineering and construction management or related field or fifteen (15) years of experience in supervising line operations. Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required Thorough knowledge of GO 95/165 and Construction Methods	N/A	100%	N/A	None required
Regulatory Compliance Project Engineer (BVES Employee)	Bachelor's Degree in Electrical Engineering, or related field. Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable. Excellent knowledge and strong experience in working in a highly regulated environment and working with a large number of agencies such as: US Forest Service, US Bureau of Land Management, US Fish and Wildlife Service, California Department of Fish and Game, California Division of Occupational Safety and Health (DOSH, also known as Cal/OSHA), California Department of Transportation (Caltrans), Department of Transportation (DOT), State Water Resource Control Board, California Environmental Protection Agency (EPA), and South Coast Air Quality Management District (SCAQMD). Experience with California Environmental Quality Act (CEQA) process. Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174.	Professional Engineer's (PE) license in the California is strongly desired. Note, that if the applicant does not have a PE in California, the applicant will be required to obtain a California PE license within 12 months of employment at BVES, Inc. in this position.	50%	100%	None required

6 PERFORMANCE METRICS AND UNDERLYING DATA

Instructions: Section to be populated from Quarterly Reports. Tables to be populated are listed below for reference.

NOTE: Report updates to projected metrics that are now actuals (e.g., projected 2021 spend will be replaced with actual unless otherwise noted). If an actual is substantially different from the projected (>10% difference), highlight the corresponding metric in light green.

Highlighting variances in projections cannot easily be produced as cost accounting methodologies have been modified to include disaggregation of wildfire mitigation plan activities for this revision. BVES has allocated expenditures based on accounting principles and methodologies to result in appropriate spread of costs associated with applicable mitigation initiative activities.

6.1 Recent Performance on Progress Metrics, Last 7 Years

Instructions for Table 1 of Attachment 3:

In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, each utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.

Table 1 of Attachment 3: Recent performance on progress metrics, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 1: Recent Performance on Progress Metrics, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 1**.

6.2 Recent Performance on Outcome Metrics, Annual, Last 7 Years

Instructions for Table 2 of Attachment 3:

In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Risk events and utility-related ignitions are normalized by wind warning status (RFW & HWW). Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in "Comments" column.

Provide a list of all types of findings and number of findings per type, in total and in number of findings per circuit mile.

Table 2 of Attachment 3: Recent performance on outcome metrics, last 7 years– reference only, fill out attached spreadsheet to correct prior reports

Table 2: Recent Performance on Outcome Metrics, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 2**.

6.3 Description of Additional Metrics

Instructions for Table 3 of Attachment 3:

In addition to the metrics specified above, list and describe all other metrics the utility uses to evaluate wildfire mitigation performance, the utility's performance on those metrics over the last seven years, the units reported, the assumptions that underlie the use of those metrics, and how the performance reported could be validated by third parties outside the utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each preventive strategy and program.

Table 3 of Attachment 3: List and description of additional metrics, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 3: List and description of additional metrics, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 3**.

6.4 Detailed Information Supporting Outcome Metrics

Enclose detailed information as requested for the metrics below.

Instructions for Table 4 of Attachment 3:

In the attached spreadsheet document, report numbers of fatalities attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last five years as needed to correct previously reported data. For fatalities caused by initiatives beyond these categories, add rows to specify accordingly. The relationship to the utility statuses of full-time employee, contractor, and member of public are mutually exclusive, such that no individual can be counted in more than one category, nor can any individual fatality be attributed to more than one initiative.

Table 4 of Attachment 3: Fatalities due to utility wildfire mitigation initiatives, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 4: Fatalities due to utility wildfire mitigation initiatives, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 4**.

Instructions for Table 5 of Attachment 3:

In the attached spreadsheet document, report numbers of OSHA-reportable injuries attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last seven years as needed to correct previously reported data. For members of the public, all injuries that meet OSHA-reportable standards of severity (i.e., injury or illness resulting in loss of consciousness or requiring medical treatment beyond first aid) must be included, even if those incidents are not reported to OSHA due to the identity of the victims.

For OSHA-reportable injuries caused by initiatives beyond these categories, add rows to specify accordingly. The victim identities listed are mutually exclusive, such that no individual victim can be *counted as more than one identity, nor can any individual OSHA-reportable injury be attributed to more than one activity.*

Table 5 of Attachment 3: OSHA-reportable injuries due to utility wildfire mitigation initiatives, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 5: OSHA-reportable injuries due to utility wildfire mitigation initiatives, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 5**.

6.5 Mapping Recent, Modelled, and Baseline Conditions

The utility must provide underlying data for recent conditions (over the last five years) of the utility's service territory in a downloadable shapefile GIS format, following the spatial reporting schema.[39] *All data is reported quarterly, this is a placeholder for quarterly spatial data.*

Please refer to **AttachB_2022-05-06_BVES_2022_WMP-Update-Spatial_R0.gdb.zip** submitted concurrently with this WMP.

6.6 Recent Weather Patterns, Last 7 Years

Instructions for Table 6 of Attachment 3:

In the attached spreadsheet document, report weather measurements based upon the duration and scope of NWS Red Flag Warnings, High wind warnings and upon proprietary Fire Potential Index (or other similar fire risk potential measure if used) for each year. Calculate and report 5-year historical average as needed to correct previously reported data.

Table 6 of Attachment 3: Weather patterns, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 6: Weather patterns, last 7 years is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 6**.

6.7 Recent and Projected Drivers of Outages and Ignition Probability

Instructions for Table 7.1 and 7.2 of Attachment 3:

(Table 7.1) In the attached spreadsheet document, report recent drivers of outages according to whether or not risk events of that type are tracked, the number of incidents per year (e.g., all instances of animal contact regardless of whether they caused an outage, an ignition, or neither), the rate at which those incidents (e.g., object contact, equipment failure, etc.) cause an ignition in the column, and the number of ignitions that those incidents caused by category, for each of last seven years as needed to correct previously-reported data. Calculate and include 5-year historical averages. This requirement applies to all utilities, not only those required to submit annual ignition data. Any utility that does not have complete 2021 ignition data compiled by the WMP deadline is required to indicate in the 2021 columns that said information is incomplete. (Table 7.2) Similar to Table 7.1, but for ignition probability by line type and HFTD status, according to if ignitions are tracked.

[39] https://energysafety.ca.gov/wp-content/uploads/energy-safety-gis-data-reporting-standard_version2.1_09072021_final.pdf

Table 7.1 of Attachment 3: Key recent and projected drivers of outages, last 7 years and projections – reference only, fill out attached spreadsheet to correct prior reports

Table 7.1: Key recent and projected drivers of ignition probability, last 7 years and projections is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 7.1**.

Table 7.2 of Attachment 3: Key recent and projected drivers of ignition probability by Line type and HFTD status, last 7 years and projections – reference only, fill out attached spreadsheet to correct prior reports

Table 7.2: Key recent and projected drivers of ignition probability by HFTD status, last 7 years and projections is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 7.2**.

6.8 Baseline State of Equipment and Wildfire and PSPS Event Risk Reduction Plans

6.8.1 Current Baseline Status of Service Territory and Utility Equipment

Instructions for Table 8 of Attachment 3:

In the attached spreadsheet document, provide summary data for the current baseline state of HFTD and non-HFTD service territory in terms of circuit miles; overhead transmission lines, overhead distribution lines, substations, weather stations, and critical facilities located within the territory; and customers by type, located in urban versus rural versus highly rural areas and including the subset within the Wildland-Urban Interface (WUI) as needed to correct previously reported data.

The totals of the cells for each category of information (e.g., "circuit miles (including WUI and non-WUI)") would be equal to the overall service territory total (e.g., total circuit miles). For example, the total of number of customers in urban, rural, and highly rural areas of HFTD plus those in urban, rural, and highly rural areas of non-HFTD would equal the total number of customers of the entire service territory.

Table 8 of Attachment 3: State of service territory and utility equipment – reference only, fill out attached spreadsheet to correct prior reports

Table 8: State of service territory and utility equipment is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 8**.

6.8.2 Additions, Removal, and Upgrade of Utility Equipment by End of 3-Year Plan Term

Instructions for Table 9 of Attachment 3:

In the attached spreadsheet document, input summary information of plans and actuals for additions or removals of utility equipment as needed to correct previously reported data. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Report changes planned or actualized for that year – for example, if 10 net overhead circuit miles are added in 2020, then report "10" for 2020. If 20 net overhead circuit miles are planned for addition by 2022, with 15 being added by 2021 and 5 more added by 2022, then report "15" for 2022 and "5" for 2021. Do not report cumulative change across years. In this case, do not report "20" for 2022, but instead the number planned to be added for just that year, which is "5".

Table 9 of Attachment 3: Location of actual and planned utility equipment additions or removal year over year – reference only, fill out attached spreadsheet to correct prior reports

Table 9: Location of actual and planned utility equipment additions or removal year over year is provided in **Attachment A** to this WMP 2022 Update and in **Appendix D QDR Table 9**.

Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.

Instructions for Table 10 of Attachment 3:

Referring to the program targets discussed above, report plans and actuals for hardening upgrades in detail in the attached spreadsheet document. Report in terms of number of circuit miles or stations to be upgraded for each year, assuming complete implementation of wildfire mitigation activities, for HFTD and non-HFTD service territory for circuit miles of overhead transmission lines, circuit miles of overhead distribution lines, circuit miles of overhead transmission lines located in Wildland- Urban Interface (WUI), circuit miles of overhead distribution lines in WUI, number of substations, number of substations in WUI, number of weather stations and number of weather stations in WUI as needed to correct previously-reported data. If updating previously reported data, separately include a list of the hardening initiatives included in the calculations for the table.

Table 10 of Attachment 3: Location of actual and planned utility infrastructure upgrades year over year – reference only, fill out attached spreadsheet to correct prior reports.

Table 10: Location of actual and planned utility infrastructure upgrades year over year is provided in **Attachment A** to this WMP 2022 Update in **Appendix D QDR Table 10**.

7 MITIGATION INITIATIVES

7.1 Wildfire Mitigation Strategy

Describe organization-wide wildfire mitigation strategy and goals for each of the following time periods, highlighting changes since the prior WMP report:

1. By June 1 of current year

2. By Sept 1 of current year

3. Before the next Annual WMP Update

4. Within the next 3 years

5. Within the next 10 years

The description of utility wildfire mitigation strategy must:

Discuss the utility's approach to determining how to manage wildfire risk (in terms of ignition probability and estimated wildfire consequence) as distinct from managing risks to safety and/or reliability. Describe how this determination is made both for (1) the types of activities needed and (2) the extent of those activities needed to mitigate these two different groups of risks. Describe to what degree the activities needed to manage wildfire risk may be incremental to those needed to address safety and/or reliability risks.

Discuss how risk modeling outcomes are used to inform decision-making processes and used to prioritize mitigation activities. Provide detailed descriptions including clear evaluation criteria[40] and visual aids (such as flow charts or decision trees). Provide an appendix (including use of relevant visual aids) with specific examples demonstrating how risk modeling outcomes are used in prioritizing circuit segments and selecting mitigation measures.

Include a summary of achievements of major investments and implementation of wildfire mitigation initiatives over the past year, lessons learned, changed circumstances during the 2020-2022 WMP plan cycle, and corresponding adjustment in priorities for the current year. Organize summaries of initiatives by the wildfire mitigation categories listed in Section 7.3.

List and describe all challenges associated with limited resources and how these challenges are expected to evolve over the next 3 years.

Outline how the utility expects new technologies and innovations to impact the utility's strategy and implementation approach over the next 3 years, including the utility's program for integrating new technologies into the utility's grid. Include utility research listed above in Section 4.4.

Provide a GIS layer[41] showing wildfire risk (e.g., MAVF); data should be as granular as possible.

Provide GIS layers[42] for the following grid hardening initiatives: covered conductor installation;[43] undergrounding of electrical lines and/or equipment; and removal of electrical lines. Features must have

[40] "Evaluation criteria" should include all points of considerations including any thresholds and weights that may affect the outcome of their decision, as well as a descriptor of how it is evaluated (i.e., given a risk score, using SME expertise to determine that score, using a formula).

[41] GIS data that has corresponding feature classes in the most current version of Energy Safety GIS Data

[42] Energy Safety acknowledges potential security concerns regarding aggregating and presenting critical

electrical infrastructure in map form. Utilities may provide maps or GIS layers required by these Guidelines as confidential attachments when necessary.

[43] For a definition of "covered conductor installation" see Section 9 of Attachment 2.

the following attributes: state of hardening, type of hardening where known (i.e., undergrounding, covered conductors, or removal), and expected completion date. Provide as much detail as possible (circuit segment, circuit- level, etc.). The layers must include the following:

Hardening planned for 2022

Hardening planned for 2023

Hardening planned for 2024

Provide static (either in text or in an appendix), high-level maps of the areas where the utility will be prioritizing Grid Design and System Harding initiatives for 2022, 2023, and by 2032.

Provide a GIS layer for planned Asset Management and Inspections in 2022. Features must include the following attributes: type, timing, and prioritization of asset inspection. Inspection types must follow the same types described in Section 7.3.4, Asset Management and Inspections, and as applicable, should not be limited to patrols and detailed inspections.

Provide a GIS layer illustrating where enhanced clearances (12 feet or more) were achieved in 2020 and 2021, and where the utility plans to achieve enhanced clearances in 2022. Feature attributes must include clearance distance greater than or equal to 12 feet, if such data is available, either in ranges or as discrete integers (e.g., 12-15 feet, 15-20 feet, etc. OR 12, 13, 14, 15, etc.).

This section describes the wildfire mitigation strategies and programs established in the WMP. The information provided includes the overarching strategy, initiatives, projects implemented and proposed, and the timing of proposed implementations. BVES did not split its preventive strategies into transmission and distribution categories because BVES does not own or operate any transmission infrastructure. Although BVES has sub-transmission lines (34.5 kV), it considers the lines distribution assets, given the voltage.[44]

The following describes the organization-wide wildfire mitigation strategy statements over the same periods:

***1.** and **2.** Before the 2021 wildfire season[45]:*

The following table summarizes grid hardening project targets through Q3 2022.

Table 7.1-1: 2022 Targets Through Q3 - CAPEX

Initiative	Target Units	Target Q1	Target Q1 + Q2	Target Q1 + Q2 + Q3
Install Fault Indicators (FIs) Project	# of FIs	0	0	20
Covered Conductor Project	Circuit Miles	1.5	2.5	8.9

[44] Distribution lines are defined as all lines below 65 kV per Attachment 1 to R.18-10-007 filed 12/16/19 at 11:53 AM

[45] BVES does not distinguish actions planned for before June 1 and September 1 in its planning at this time. BVES includes metric tracking by quarter, which aligns to the quarterly report methodology.

Initiative	Target Units	Target Q1	Target Q1 + Q2	Target Q1 + Q2 + Q3
Radford Line Replacement Project	Circuit Miles	0	0	1
	# of Fire Resistant Poles Installed	0	0	22
Pole Loading Project	# of Poles Replaced	10	40	100
	# of Poles Assessed	25	75	150
Tree Attachment Removal Program	# of Tree Attachments Removed	0	0	30
Evacuation Route Hardening Project	# of Poles Hardened with Wire Mesh Wrap	350	412	412
Grid Automation Project	# of Substations Connected to SCADA Network	0	1	2

The following table summarizes operations and maintenance (O&M) project targets through Q3 2022.

Table 7.1-2: 2022 Targets Through Q3 - OPEX

Initiative	Target Units	Target Q1	Target Q1 + Q2	Target Q1 + Q2 + Q3
GO-165 Detailed Inspections	Circuit Miles	11	29	29
GO-165 Patrol Inspections	Circuit Miles	85	85	160
UAV Thermography Program (Aerial Inspection)	Circuit Miles	0	0	211
UAV HD Photographic/Video Inspection Program (Aerial Inspection)	Circuit Miles	0	0	211
Intrusive Pole Inspection Program	# of Poles Tested	0	0	850

Initiative	Target Units	Target Q1	Target Q1 + Q2	Target Q1 + Q2 + Q3
LiDAR Inspection Program	Circuit Miles	0	0	211
Third Party Ground Patrol	Circuit Miles	0	0	211
GO-174 Substation Inspection Program	# of Substations Inspected	36	72	108
Vegetation Management Quality Control Checks	# of Vegetation Management QCs	18	36	54
Achieving Line Clearances from Vegetation	Circuit Miles	18	36	54
Removal of Trees with Strike Potential on Lines	# of Trees Removed	18	36	66

BVES will conduct the following to prepare for the 2022 wildfire season and beyond to systematically reduce wildfire ignition risk through:

- System hardening and automation initiatives
- Improved preventive maintenance practices and inspection techniques
- Additional risk mapping and modeling engagements
- Continued coordination with public safety partners and community members for development of protocols, emergency response planning and public communications for wildfires and PSPS events

BVES is scheduled to complete its GO 165 patrols before June 1st of each year. BVES is also scheduled to complete LiDAR surveys and Third-Party Ground patrols by September 1st. BVES intends to complete its Fly-over UAV surveys by September 1st.

All BVES outreach on PSPS policy and procedures are scheduled to be completed or scheduled by June 1st. Additionally, all long-term preparations for PSPS events (such as CRC materials inventory and stocking) are scheduled to be completed by June 1st. BVES conducted a tabletop exercise of PSPS activation and response on April 14, 2022. Currently, BVES is updating its PSPS plan and protocols to align with the Phase 3 PSPS guidelines and lessons learned from the tabletop exercise.[46]

BVES staff will continue to conduct in-house training on PSPS procedures, wildfire emergency response and recovery procedures, and operations procedures to mitigate wildfire. BVES has scheduled a PSPS

[46] CPUC. “Decision Adopting Phase 3 Revised and Additional Guidelines and Rules for Public Safety Power Shutoffs (Proactive De-Energizations) of Electric Facilities to Mitigate Wildfire Risk Caused by Utility Infrastructure,” R. 18-12-005, D. 21-06-034, June 24, 2021.

functional exercise on June 21, 2022 and has invited state and local government and stakeholder partners to participate in the event.

3. Before the next annual update:

The following table summarizes grid hardening project targets in Q4.

Table 7.1-3: 2021 Targets in Q4 – CAPEX

Initiative	Target Units	Target Q4	Annual Cumulative Target Q1 + Q2 + Q3 + Q4
Install Fault Indicators (FIs) Project	# of FIs	30	50
Covered Conductor Project	Circuit Miles	4	12.9
Radford Line Replacement Project	Circuit Miles	1.7	2.7
	# of Fire Resistant Poles Installed	48	70
Pole Loading Project	# of Poles Replaced	65	165
	# of Poles Assessed	75	225
Tree Attachment Removal Program	# of Tree Attachments Removed	50	80
Evacuation Route Hardening Project	# of Poles Hardened with Wire Mesh Wrap	0	412
Grid Automation Project	# of Substations Connected to SCADA Network	1	3

The following table summarizes O&M project targets in Q4.

Table 7.1-4: 2022 Targets in Q4 - OPEX

Initiative	Target Units	Target Q4	Annual Cumulative Target Q1 + Q2 + Q3 + Q4
GO-165 Detailed Inspections	Circuit Miles	0	29

Initiative	Target Units	Target Q4	Annual Cumulative Target Q1 + Q2 + Q3 + Q4
GO-165 Patrol Inspections	Circuit Miles	95	255
UAV Thermography Program (Aerial Inspection)	Circuit Miles	0	211
UAV HD Photographic/Video Inspection Program (Aerial Inspection)	Circuit Miles	0	211
Intrusive Pole Inspection Program	# of Poles Tested	0	850
LiDAR Inspection Program	Circuit Miles	0	211
Third Party Ground Patrol	Circuit Miles	0	211
GO-174 Substation Inspection Program	# of Substations Inspected	36	144
Vegetation Management Quality Control Checks	# of Vegetation Management QCs	18	72
Achieving Line Clearances from Vegetation	Circuit Miles	18	72
Removal of Trees with Strike Potential on Lines	# of Trees Removed	22	88

BVES will complete the hardening of all primary evacuation routes by the end of 2022. BVES activities ahead of the next annual update include continuing to refine data governance practices and incorporate feedback derived from the risk modeling and mapping process to better understand unique areas of the service territory with greater climate change influenced risk. These goals center around developing associated actions and initiatives in preparation for the next annual update through:

- Using established metrics, monitor the effectiveness WMP initiatives and associated wildfire risk reductions
- Contract with Technosylva to further enhance mapping and modeling capabilities of wildfire and PSPS risk evaluation
- Improve GIS capabilities, data gathering, and continue to align with data schema

Gather internal and external (from other CA utilities) lessons learned from wildfire risk modeling, program implementation and effectiveness, pilot projects and new technology

4. Within the next three years:

Within the next three years, BVES aims to continue mitigation measures to reduce the number of high-risk circuits from seven to four (see **Table 4.3-2** for details) by completion of wildfire risk reduction initiatives and improvements to wildfire risk modeling, situational awareness, internal capabilities and external stakeholder communications and outreach. BVES also aims to initiate evacuation route hardening along secondary evacuation routes. BVES targets to establish enhanced modeling capabilities for real-time weather and fire risk conditions monitoring. BVES is also on track to improve current GIS asset and mitigation implementation digitization with in-house and contracted support in support of the quarterly spatial data filings. Additionally, in anticipation of any PSPS activations or loss of supply from SCE due to proactive de-energization, BVES plans to install both a solar and storage system to provide backup power in conjunction with the BVPP.

5. In the next ten years:

Within a decade, BVES strives to continue mitigation measures to reduce the number of high-risk and moderate circuits to 0 by completion of wildfire risk reduction initiatives and improvements to wildfire risk modeling, situational awareness, internal capabilities, and external stakeholder communications and outreach through:

100% completion of replacing all sub-transmission bare conductors with covered wire100% completion of replacing all high-risk distribution bare conductors with covered wire
100% completion of tree attachment removal program
100% completion of evacuation route hardening (primary and secondary evacuation routes)
Implementation of additional grid hardening initiatives, ignition risk modeling, online diagnostics and remote monitoring technologies, and other wildfire risk reduction technologies and plans

Wildfire Risk Management (Ignition Probability/Consequence) Compared to Safety/Reliability

BVES selected the proposed initiatives in this WMP, following the assessment of key wildfire risk drivers and quantifying which approaches most cost-effectively reduced risks, to reduce the probability of ignition by utility equipment while minimizing the impact of wildfires on reliable electric service. Public safety impact is a principal consideration within BVES normal and emergency operating practices.

Using the risk-based decision-making framework, current programmatic targets, and applied lessons learned, BVES continues to enhance its existing wildfire mitigation practices for the 2022 WMP. Each subsection under **Section 7.3** details the planning, execution, and cost components of existing and planned mitigation measures in addition to alternative assessments, where applicable, and how proposed practices will mitigate wildfire ignition and consequences. BVES reviews each mitigation practice in this section at least annually to evaluate progress and determine if modification to the WMP is appropriate. These initiatives largely complement BVES's standard activities undertaken to manage risks to safety and reliability. Enhanced preventive maintenance, vegetation management, inspection frequency, and pole remediation all reduce wildfire, safety, and reliability risks.

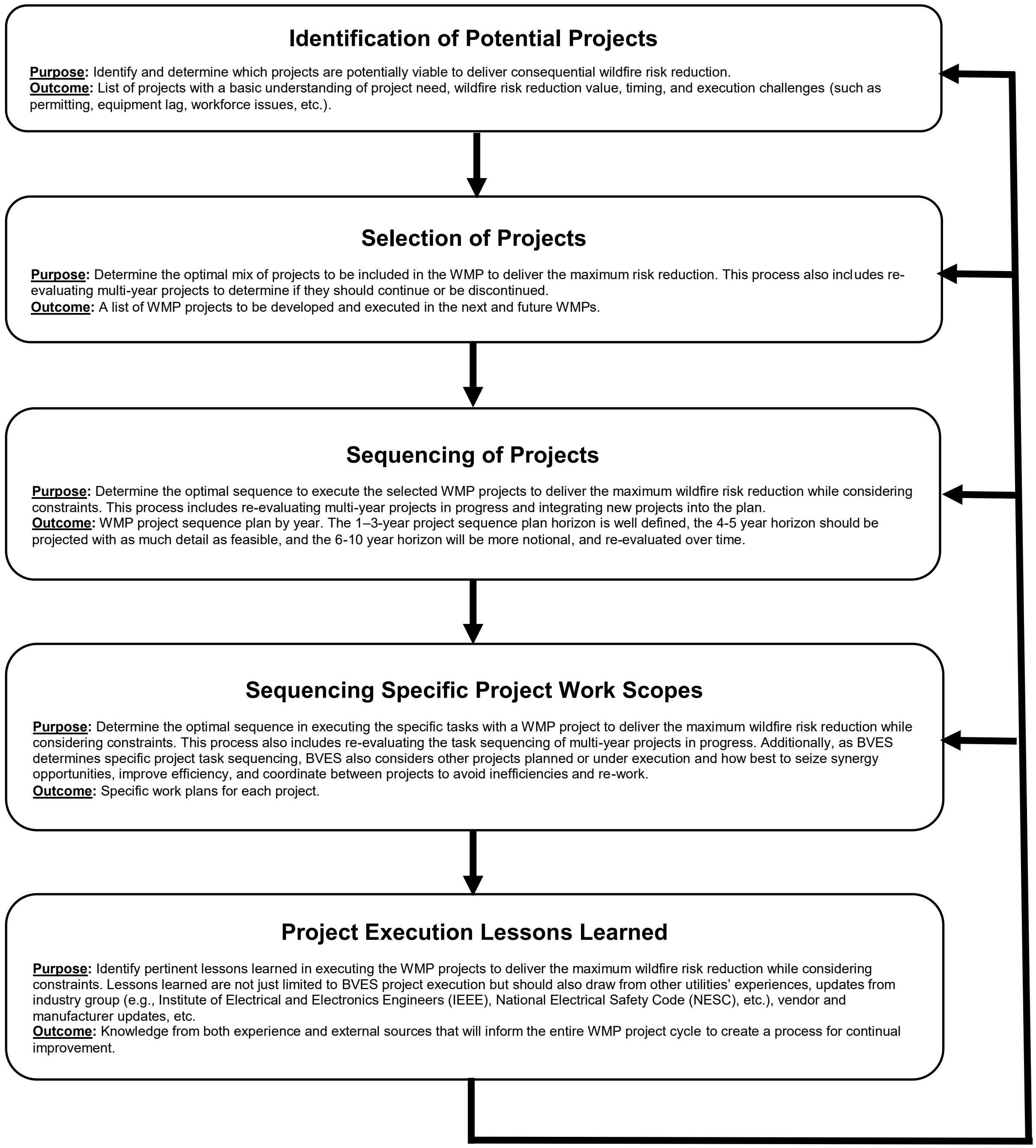
Risk Modeling Outcomes Used to Inform Decision-Making Processes and Initiative Prioritization

BVES leverages the outcomes of its Risk Register and Fire Safety Circuit matrix to prioritize short and long-term efforts. To date, this approach has yielded successful implementation and realized risk reduction as demonstrated by the Fire Safety Circuit Matrix projections. In 2021, REAX Engineering provided BVES with static maps based on historical and forecasted weather and fuel conditions to better understand fire impact in its territory. BVES relies on simulations and forecasts as there have not been any significant ignition events requiring reporting to the Commission. In 2022, BVES will continue to better understand its service area through quantitative means through engagement with Technosylva. Purchasing software subscriptions to this entity's network will not only provide anecdotes from similar utility terrains, but also will have personalized characteristics during real-time conditions to provide BVES granular awareness into the risks that may be present in its service territory. After deployment, the combination of these risk models and maps will support BVES's ability to better identify the appropriate mitigations for the actualized threat in its service area. BVES will also be able to balance the need for safety and reliability and public safety in terms of wildfire and PSPS threats.

WMP Project Selection and Prioritization Process

The following figure illustrates the process BVES management utilizes to identify WMP projects, select WMP project, sequence WMP projects and sequence specific WMP project work scopes for each WMP or WMP update.

Figure 7.1-1: WMP Project Selection and Prioritization Process



Identification of Potential Projects: This step is designed to identify and determine which projects are potentially viable to deliver consequential wildfire risk reduction. The outcome of this step is an integrated list of projects with a basic understanding of project need, wildfire risk reduction value, timing, and execution challenges, such as permitting, equipment lag, workforce issues, etc. For each potential project, the risk reduction value and risk spend efficiency is calculated using the Risk-Based Decision-Making process as required for SMJUs by Commission Rulemaking 20-07-013 the Risk-Base Decision-Making process is described in Decision D.19-08-027 and in **Section 4.2** of this WMP. In order for BVES to obtain a reasonable assessment of the risk reduction and risk spend efficiency for each project, BVES always seeks to understand to what degree will the risk reduction work be achieved and, if achievable or partly achievable and at what cost. The following factors are developed and considered by the management team:

- Desired scope of work (what technical specifications will the project achieve)
- Technology risk (is technology mature, used in California, new, etc.)
- Site availability and evaluation (constrained to existing facilities or new property; easements; access for construction, inspection, and O&M; zoning; endangered species, other protected species, cultural or historical concerns, or other environmental issues; impact on neighboring community during construction and following project, etc.)
- Permitting (are permits required; approval authority(ies); complexity and timeline of permitting process; request from within the Company or contract out to a permitting expert consultant, etc.)
- Availability of material and equipment (delivery lead-time, type of material – special order made to specifications or commodity, etc.)
- Access to qualified labor resources (mobilization/demobilization, Company labor or contracted labor, work hours – day, night, weekends, shift work, etc.)
- Design process (design complexity; can the design be performed within the Company or must it be contracted out; timeline to produce construction grade design, design risk (e.g., during the course design, how likely is it that the scope of the project may be altered and by how much), etc.)
- Stakeholder support (internal approval, regulatory support, public and local stakeholder support)
- Length of construction period (multi-year, work all year round or only during non-winter snow period, etc.)
- Project used and useful timeframe (as the project is constructed is it put in service, put in service in distinct phases, or at end of project)

From the above consideration, management develops the cost of the project, the estimated timeline and sequence of the project, and the risk reduction achieved going back to the Risk-Based Decision-Making model for SMJUs. From these, risk spend efficiency is calculated.

Selection of Projects: In this step, management uses the information developed in the prior step to develop the optimal mix of projects to be included in the WMP (and follow-on updates to the WMP) to deliver maximum risk reduction. This process also includes re-evaluating multi-year projects that are in progress to determine if they should be continued or discontinued. The expected outcome of this step is to develop an integrated and prioritized list of WMP projects to be developed and executed in the next and future WMPs. The list of selected projects is not sequenced in this step. Alternatives to the projects are considered and some projects are removed from consideration in this step.

The risk reductions and RSEs, developed using the Risk-Based Making-Decision process per the previous step, are utilized to establish an initial project selection screening. Then, the resulting outcome of executing the project is projected in the Fire Safety Matrix model described in **Section 4.2** of this WMP. This provides more granular information at the circuit level. It should be noted that BVES's circuits are not long by comparison to many utilities. The longest circuit is 23.9 circuit miles (8 of those circuit miles are underground) and most circuits are less than 10 circuit miles in length. Additionally, the projects are viewed against the Risk Maps developed by Reax Engineering describe in **Section 4.2** of this WMP are used to determine where the wildfire mitigation greatest risk benefit may be achieved by each project.

Sequencing of Projects: In this step, management uses the information developed in the prior step to develop the optimal sequence in executing the selected WMP projects to deliver the maximum wildfire risk reduction while balancing constraints (siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.). This process also includes re-evaluating the pace at which multi-year projects in progress are to be executed, or even paused. The expected outcome of this step is to develop a well-sequenced WMP integrated risk-based project plan by year. The plan's 1-3 year horizon is mostly well defined, the 4-5 year horizon is projected with as much detail as feasible, and the 6-10 year horizon is more notional.

This step focuses on allocating resources to the projects that are ready to execute given project constraints (siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.) in a risk-based prioritized manner based on the information from the prior steps. A project may have a large risk reduction but permitting for the project is lengthy and may still be in progress; therefore, other projects with consequential risk benefit are sequenced ahead of the high risk-benefit project until it is ready to execute. This approach allows BVES to continuously make risk reduction progress in its grid hardening efforts.

Sequencing Specific Project Work Scopes: In this step, management determines the optimal sequence in executing the specific tasks within each of the selected WMP projects to deliver the maximum wildfire risk reduction while considering constraints (siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.). This process also includes re-evaluating the task sequencing of multi-year projects in progress. Additionally, in determining specific project task sequencing, this step also considers other projects being executed and how best to seize synergy opportunities, improve resource allocation efficiency, stay focused on achieving the greatest risk reduction, and coordinate between projects to avoid inefficiencies, unnecessary delays, and re-work.

In sequencing projects, the focus is risk reduction. BVES prioritizes and plans work based upon the highest relative risk areas as determined in the Fire Safety Matrix model described in **Section 4.2** of this WMP and the Risk Maps developed by Reax Engineering describe in **Section 4.2** of this WMP. It should be noted that Bear Valley's entire 32 square mile service area is "high risk." The service area is considered "Very Dry" or "Dry" per the National Fire Danger Rating System (NFDRS) over 75 percent of the time. The service area terrain is characterized with a high density of vegetation – trees and shrubs. The CPUC Fire-Threat Map adopted January 19, 2018, designated Bear Valley's service area as being in the High Fire-Threat District (HFTD) with approximately 90% in Tier 2 (elevated risk) and the remaining 10% in Tier 3 (extreme risk) areas. The Cal Fire California Fire Hazard Severity Zone Map Update Project rates Bear Valley's service area as "Very High Fire Hazard Severity Zone." While one can rank the relative risk of BVES's facilities within the service area, it should be understood that all of BVES's service area is high risk. In such a small service area, an ignition anywhere can produce embers that the wind can carry just a few blocks away and cause a wildfire. In achieving the highest risk reduction, BVES most allow temper execution within the typical project constraints related to siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.

Project Execution Lessons Learned: This step is executed throughout the process since lessons are learned at every step of the process and it would be inefficient to wait to make course corrections where appropriate. Management uses its experience as well as external information to determine pertinent lessons learned in executing the WMP projects to deliver the maximum wildfire risk reduction while considering constraints. Lessons learned are not just limited to project execution but also from other utilities' experiences, updates from industry group (e.g., Institute of Electrical and Electronics Engineers (IEEE), National Electrical Safety Code (NESC), etc.), vendor and manufacturer updates, etc. The intended outcome is developing knowledge from both experience and external sources that will inform the entire WMP project cycle to create a process for continual improvement.

Risk models are re-evaluated to ensure resources are allocated using the best information at the time. BVES is currently working with an expert consultant in wildfire risk modeling, Technosylva, to develop improved wildfire risk models that better model installed assets and forecast risk reduction based on projected project outcomes. BVES expects to use the Technosylva model to inform its 2023 WMP.

See the table below for the summarized responses to identified prompts above. Additional detail on implementation of initiatives is located in **Section 5.3** and **Section 7.3** of this WMP.

Table 7.1-5: Listed Description of the Wildfire Mitigation Strategy

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk *7.1 (A)*		Summary of Implementation & Changed Circumstances *7.1 (C)*	Resource Sufficiency by 2025 *7.1 (D)*	New Technologies & Innovation by 2025 *7.1 (E)*
	Reliability / Safety (%)	Wildfire (%)			
Risk Assessment & Mapping	10	90	- BVES began enhancing its GIS mapping capabilities in 2020 and improved them further over the course of 2021. - In moving toward alignment with the OEIS's data schema methodology, BVES contracted SMEs to assist in enhancing existing risk models and expand into fire ignition predictability models to enhance the utility's ability to provide more accurate forecasts of threats. - BVES will employ Technosylva to establish parameters for BVES to access its subscription software for real-time fire risk modeling and impact analysis. See initiative **Section 7.3.1** for additional lessons learned, challenges, program status, and outcomes.	BVES has contracted resources to support the initiatives. Training internal utility staff is expected as part of this engagement.	BVES continues to monitor the large utility deployments and considerations of new vendors and engineering firms to consider when expanding probability scenario mapping to risk drivers.
Situational Awareness & Forecasting	20	80	- BVES installed its final two weather stations in 2021. There now exists a complete picture of the weather, including microclimates, of the compact BVES service territory. - GIS improved its applications and incorporated the risk mapping and data governance	BVES has contracted resources to support the initiatives along with internal resources to interpret weather station and	BVES expects to explore online diagnostic technologies and other remote monitoring devices over

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk 7.1 (A)		Summary of Implementation & Changed Circumstances 7.1 (C)	Resource Sufficiency by 2025 7.1 (D)	New Technologies & Innovation by 2025 7.1 (E)
	Reliability / Safety (%)	Wildfire (%)			
			initiatives performed in 2021. - BVES completed installing its fiber network throughout its service area, which will allow additional monitoring devices in the future - Situational Awareness Enhancement Center is scheduled for 2022 - Remote monitoring via camera requires future improvements for a design for remote locations where no low voltage secondary exist. Developing design for solar and battery power. See initiative **Section 7.3.2** for additional lessons learned, challenges, program status, and outcomes.	camera imaging data.	the next three years.
Grid Design & System Hardening	10	90	-Upgrades to Palomino Substation were executed in 2021. - BVES Energy Storage Facility has made more strides in determining a plan and site approvals for installation. This initiative has been pushed out to 2023. - All Conventional (Expulsion) Fuse Replacements have been fully replaced as of December 31, 2021. - Tree Attachments have a forecasted schedule of removal by 2026. - BVES completed the pilot for Evacuation Route hardening. - Pole Loading Assessment & Remediation is on track given the number of corrective actions throughout 2021. - Completion of the Covered Conductor pilot program - Radford Line Covered Conductor Replacement Project	BVES faces inherent challenges as a small, remotely located utility and continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources and internal personnel are expected to meet the utility's needs.	BVES continues to monitor the large utility deployments and considerations of new vendors and engineering firms, and academic research that identifies successful technologies that are demonstrated to mitigate the risk of wildfires. BVES has a robust hardening plan and does not anticipate adoption of

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk 7.1 (A)		Summary of Implementation & Changed Circumstances 7.1 (C)	Resource Sufficiency by 2025 7.1 (D)	New Technologies & Innovation by 2025 7.1 (E)
	Reliability / Safety (%)	Wildfire (%)			
			is on track for completion in 2022. - Covered Wire installations for the 34.5 and 4kV lines will continue given the success of the covered conductor pilot program. See initiative **Section 7.3.3** for additional lessons learned, challenges, program status, and outcomes.		new technologies within the next three years but will continue to evaluate and consider emerging advancements and technologies.
Asset Management & Inspections	20	80	- All inspection programs remain on target with priority corrective actions addressed promptly or within a defined timeframe between level 1-3 occurrences. BVES does not expect changes over the WMP filing period. - BVES contracted with a qualified contractor with experience in UAV inspection type to perform an annual fly-over inspection of BVES facilities to conduct thermography and HD photography/videography. This inspection is performed prior to the fire season. See initiative **Section 7.3.4** for additional lessons learned, challenges, program status, and outcomes.	BVES faces inherent challenges as a small, remotely located utility and continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources and internal personnel are expected to meet the utility's needs.	BVES does not anticipate any new technologies or innovation within this WMP category over the next three years.
Vegetation Management & Inspections	10	90	- BVES continues to execute its enhanced vegetation management program focusing on developing collaborative measures with the USFS	BVES faces inherent challenges as a small, remotely located utility and	BVES does not anticipate any new technologies or innovation

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk *7.1 (A)*		Summary of Implementation & Changed Circumstances *7.1 (C)*	Resource Sufficiency by 2025 *7.1 (D)*	New Technologies & Innovation by 2025 *7.1 (E)*
	Reliability / Safety (%)	Wildfire (%)			
			- BVES hired a forester consultant to execute activities along with the utility, giving SME level oversight in elevated weather risk conditions See initiative **Section 7.3.5** for additional lessons learned, challenges, program status, and outcomes.	continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources (such as the planned forester support) and internal personnel are expected to meet the utility's needs.	within this WMP category over the next three years.
Grid Operations & Protocols	30	70	- Programs in place for emergency reports from third parties and wildfire infrastructure protection teams continue. - High-speed clearing and automatic recloser upgrades did not reveal any need to modify the schedule or scope in 2021. See initiative **Section 7.3.6** for additional lessons learned, challenges, program status, and outcomes.	BVES faces inherent challenges as a small, remotely located utility and continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources and internal personnel are expected to meet the utility's needs.	BVES does not anticipate any new technologies or innovation within this WMP category over the next three years. In the event that an PSPS event is necessary, BVES will seek to reduce any scale, scope, and impact of the event through line sectionalization efforts subject to the GIS data architecture being further enhanced over the next year.

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk 7.1 (A)		Summary of Implementation & Changed Circumstances 7.1 (C)	Resource Sufficiency by 2025 7.1 (D)	New Technologies & Innovation by 2025 7.1 (E)
	Reliability / Safety (%)	Wildfire (%)			
Data Governance	20	80	- This initiative category is dependent on the work executed under the GIS gap analysis, which is now being categorized under mapping and modeling work (Risk Assessment & Mapping) and data schema architecture. This will require BVES to revise certain aspects of data management and its existing platforms to provide more integrations in the software available to the utility at this time. See initiative **Section 7.3.7** for additional lessons learned, challenges, program status, and outcomes.	BVES faces inherent challenges as a small, remotely located utility and continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources and internal personnel are expected to meet the utility's needs.	BVES does not anticipate any new technologies or innovation within this WMP category over the next three years. The utility will continue to modify data management practices and GIS capabilities over the next year, further aligning to the OEIS's Data Schema methodology.
Resource Allocation Methodology	NA	NA	- BVES evaluates resource sufficiency as needed for both internal personnel hires and contracted third-party support See initiative **Section 7.3.8** for additional lessons learned, challenges, program status, and outcomes.	BVES faces inherent challenges as a small, remotely located utility and continues to explore cost sharing investments and mitigations to reduce resource overload and balance execution of the WMP. Over the next three years, contracted resources and internal personnel are expected to meet the utility's needs.	BVES does not anticipate any new technologies or innovation within this WMP category over the next three years.
Emergency Planning & Preparedness	40	60	- BVES did not identify any significant findings from the 2021 year associated with this	BVES personnel along with resources	BVES does not anticipate any new

Initiative Categories	Estimates of Proportion of the WMP Categories' Risk Reduction Outcomes Attributed to Reliability/Safety vs. Wildfire Risk 7.1 (A)		Summary of Implementation & Changed Circumstances 7.1 (C)	Resource Sufficiency by 2025 7.1 (D)	New Technologies & Innovation by 2025 7.1 (E)
	Reliability / Safety (%)	Wildfire (%)			
			initiative category. BVES has not experienced a wildfire or a PSPS event, nor has it had to facilitate an evacuation. - BVES continues to train staff for emergency operational roles and responsibilities and seeks to improve customer support in the event of an emergency, with particular focus to the AFN population. - BVES has deployed iRestore, which is a shared application utilized by the local emergency response district, bridging further collaboration in reducing ignition risk or wildfire spread. See initiative **Section 7.3.9** for additional lessons learned, challenges, program status, and outcomes.	available through mutual aid agreements are sufficient over the next three years.	technologies or innovation within this WMP category over the next three years.
Stakeholder Cooperation & Community Outreach	10	90	- The utility plans to enhance its communications and notification plans, starting in 2021 and continuing into 2022, and will consider designing a stakeholder outreach framework that can be standardized and used going forward to maintain strong community relations within the service area and with public safety partners. See initiative **Section 7.3.10** for additional lessons learned, challenges, program status, and outcomes.	BVES has contracted resources to support the initiatives. Training internal utility staff is expected to continue as part of this engagement.	BVES does not anticipate any new technologies or innovation within this WMP category over the next three years.

GIS Layers: Wildfire Risk, Grid Hardening, Prioritization, Asset Management, and Enhanced Clearances

The following layer characteristics are presented in the attached GIS file entitled ***AttachB_2022-05-06_BVES_2022_WMP-Update-Spatial_R0.gbd.zip***.

Customers

AFN Customers

Rural Customers

Urban Customers

Enhanced Clearances

Clearance Detail for 2020

Clearance Detail for 2021

Enhanced Clearance Grids and Attribute Log for 2020

Enhanced Clearance Grids and Attribute Log for 2021

Enhanced Clearance Grids for 2022

Grid Hardening

Covered Conductor Schedule for 2023

Covered Conductor Schedule for 2022

Fire Wrap on Poles Schedule for 2022

Weather Warnings for 2016 and 2017 HHW and RFWs

Inspections

Intrusive Pole Inspections

UAV Thermography Inspections

7.2 Wildfire Mitigation Plan Implementation

Describe the processes and procedures the electrical corporation will use to do all the following:

A. *Monitor and audit the implementation of the plan. Include what is being audited, who conducts the audits, what type of data is being collected, and how the data undergoes quality assurance and quality control.*
B. *Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies.*
C. *Monitor and audit the effectiveness of inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.*
D. *Ensure that across audits, initiatives, monitoring, and identifying deficiencies, the utility will report in a format that matches across WMPs, Quarterly Reports, Quarterly Advice Letters,[47] and annual compliance assessment.*

Monitoring and Auditing the Plan

To monitor the implementation of the WMP, the Utility Manager will provide status updates of all WMP initiatives, including identification of any deficiencies, to the President, Treasurer & Secretary, during regularly scheduled management meetings (conducted at least monthly). The President, Treasurer & Secretary maintains the responsibility of programmatic oversight across all WMP initiatives to ensure goals are tracked, recorded, and incorporated across all compliance filing mechanisms and internal record-keeping processes. The data maintained includes both qualitative and quantitative metrics which

[47] General Rule for filing Advice Letters is available in General Order 96-B: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF.

help BVES determine, among other things, whether a program reduces fire risk, is cost effective, and maintains the service level expected by BVES customers.

The WMP and its program targets are included as a discussion item at regularly scheduled Manager and Supervisor Meetings. This discussion includes the status and progress of all capital projects (such as covered wire, technical and safety upgrades to substations, pole replacements, and tree attachment removals) and operations initiatives (review of vegetation management progress, quality, and inspections) instituted under the Plan. Also, discussed are items such as preparations for fire season, PSPS exercises, and asset and vegetation inspections.

BVES meets with this external consultant, Guidehouse Inc., on a weekly basis to align all requirements of the wildfire mitigation program and ensure activities are carried out with rigorous oversight and built-in check points. Additionally, work orders, contracts, purchase orders, and other expense mechanisms are subject to BVES internal and external audit procedures. Lastly, BVES engages with one of the approved independent evaluators to review and assess BVES's compliance with its WMP on an annual basis.

Identifying and Correcting Deficiencies in the Plan

All BVES staff, contractors, and qualified external stakeholders are encouraged to offer comments, operational improvements, or identify potential deficiencies to the Utility Engineer & Wildfire Mitigation Supervisor as soon as possible when observed. All actions implemented under this WMP including capital, operations, and administrative initiatives are reviewed periodically for quality assurance and control. For example, all vegetation management is regularly inspected in the field. If any deficiency is identified, the Utility Engineer & Wildfire Mitigation Supervisor shall evaluate each reported deficiency and, if the deficiency is determined to be a valid Plan deficiency, he shall enter the deficiency into a log with the following information:

- Date the deficiency was discovered
- Description of the deficiency
- Source identifying the deficiency (e.g., patrol, internal audit)
- Priority based on deficiency severity
- Assign a corrective action including the date of planned completion
- Assign staff responsible for completing the corrective action
- Date corrective action completed

BVES also tracks deficiencies, defects, and issues identified by Energy Safety to ensure updates and corrective actions and remedies are carried out into operational processes and initiative implementation efforts. Most recently, BVES presented to Energy Safety, under filing, the November 1, 2021 Progress Report, which detailed progress and remedy implementation on issues identified for key improvements of the WMP. This filing responded to R. WSD-022, which set approval conditions for the 2021 WMP and issued areas of key improvements to the utility. The updated responses are located in **Section 4.6** and **Appendix A**. BVES operates under continuous improvement and seeks SME expertise, industry practice, and collaboration from public safety partners to ensure identified deficiencies are less frequent over time.

Monitoring and Auditing the Effectiveness of Equipment and Line Inspections

The Utility Engineer & Wildfire Mitigation Supervisor assigns qualified internal staff members (e.g., line crew or field supervisors) or engages a third party to review and audit the equipment and line inspections, including inspections performed by contractors, as defined in the WMP after the completion of the first six months of the plan. The goal is to conduct the audit between the 6-month and 8-month point of each plan period. The assigned auditor will:

- Perform site visits,

- Review records including but not limited to photographs, maps, work orders, safety records, and GIS records,
- Interview and debrief staff performing inspections to assess their knowledge of the inspection programs,
- Monitor staff performing inspection activities,
- Ensure compliance with all applicable regulatory requirements (e.g., GOs 95 and 165)
- Review identified deficiencies noted in the programs,
- Identify systemic issues or problems,
- Note the timeliness of corrective actions,
- Randomly sample completed work and corrective actions and verify the effectiveness of the work and corrective actions, and
- Issue a written findings report.

The Utility Engineer & Wildfire Mitigation Supervisor will review the audit findings and assign corrective action as applicable. A copy of the audit report will be provided to the President, Treasurer, & Secretary.

Utility Data Architecture Record Alignment and Flow

In 2021, BVES made a significant effort to improve its data architecture, collection, capabilities, and flow. This effort includes improving its GIS data quality and interface capabilities. BVES plans to continue to improve data collection, analysis, and reporting practices surrounding the evaluation of its WMP. Future plans include incorporating a data collection and tracking spreadsheet Data Product Catalog (Catalog) within its collection of data sources to aggregate the elements of various mitigation strategy results. This Catalog will allow for better, more transparent data collection and tracking both internally and externally. Finally, BVES will continue to identify new metrics and data sources to help assess the effectiveness of its implementation of the WMP.

BVES hired a new GIS administrator in March 2021. This has allowed BVES to make substantial strides in improving its GIS data governance, capabilities, and usability.

The details provided in the quarterly reports QDR, QIU, and QAL capture the descriptions of the corresponding data product to which BVES has access and regularly tracked in addition to established metrics. BVES understands the importance of delivering concise, meaningful data resources to facilitate a thorough review of the WMP and metrics and identifies, consistent with guidelines from the OEIS, and provide valuable measurements for determining the success of WMP efforts.

BVES is also beginning to institute an internal controls-based approach to better assure that wildfire management plan targets and initiatives are monitored, achieved, and audited. These internal controls include business practices, policies, and procedures designed and maintained to minimize risk. BVES's controls are designed to help prevent, detect, and correct failure points that increase wildfire risk. Accordingly, there are three categories of internal controls: preventive, detective, and corrective. It is through this perspective that BVES conducts its monitoring and implementation of the WMP. This includes activities such as detective controls including inspections, review of outage logs and incident & corrections logs, and management oversight of budgets, projects, and fault indicators. Corrective controls are the actions taken to resolve a failure. These may be prescribed actions or a framework for taking action as in the Emergency Response Plan. Implementation of these controls began in Q3 2021 and will continue into 2022.

7.3 Detailed Wildfire Mitigation Programs

Revised to address RN-BVES-22-02: BVES has not provided adequate detail on mitigation initiative progress

In In this section, describe how specific wildfire and PSPS mitigation initiatives execute the strategy set out in Section 5. The initiatives are divided into 10 categories, with each providing a space for narrative descriptions of the utility's initiatives. The initiatives are organized by the following categories provided in this section:

Risk assessment and mapping

Situational awareness and forecasting

Grid design and system hardening

Asset management and inspections

Vegetation management and inspections

Grid operations and protocols

Data governance

Resource allocation methodology

Emergency planning and preparedness

Stakeholder cooperation and community engagement

It is not necessary for a utility to have every initiative listed under each category.

7.3.a Financial Data on Mitigation Initiatives

Report actual and projected WMP expenditure, as well as the risk-spend-efficiency (RSE), for each initiative by HFTD tier (territory-wide, non-HFTD, HFTD zone 1, HFTD tier 2, HFTD tier 3) in Table 12 of Attachment 3.

Table 12 is provided in **Attachment A** to this 2022 WMP Update and in **Appendix D QDR Table 12**.

7.3.b Detailed Information on Mitigation Initiatives by Category and Activity

Report detailed information for each initiative. For each initiative, organize details under the following headings:

*1. **Risk to be mitigated** / problem to be addressed*

*2. **Initiative selection** ("why" engage in activity) – include reference to and description of a risk informed analysis and/or risk model on empirical (or projected) impact of initiative in comparison to alternatives and demonstrate that outcomes of risk model are being prioritized*

*3. **Region prioritization** ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk") and demonstrate that high-risk areas are being prioritized*

*4. **Progress on initiative** since the last WMP submission and plans, targets, and/or goals for the current year*

*5. **Future improvements to initiative** – include known future plans (beyond the current year) and new/novel strategies the utility may implement in the next 5 years (e.g., references to and strategies from pilot projects and research detailed in Section 4.4).*

***List of initiative activities by category** - Detailed definitions for each mitigation activity are provided in the appendix*

The initiatives described below include a discussion of the information requested by both 7.3.a and 7.3.b.

7.3.1 Risk Assessment and Mapping

The models BVES currently uses to determine wildfire risk reduction are discussed in detail in **Section 4.5.1**. BVES determined through collaboration and lessons learned with other utilities that further development across all initiatives in this category is warranted. BVES's 2020 GIS gap analysis revealed several areas of growth that the utility plans to continue with executing digitization improvements over the term of this WMP cycle. To improve in this area, BVES initiated an engagement on developing fire risk and consequence maps to assist in planning for future initiatives in 2021. In mid-2022, BVES will contract with Technosylva to further enhance its capabilities in providing real-time analysis into meteorological and fire risk conditions for continuous monitoring.

7.3.1.1 A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment

BVES's **Risk Mapping Program** covers initiative activities summarized risk map (**Section 7.3.1.1**), climate-driven risk mapping (**7.3.1.2**), ignition probability mapping (**7.3.1.3**), initiative mapping and estimation of risk reduction (**7.3.1.4**), and match drop simulations (**7.3.1.5**). BVES considers one major program that addresses all aspects of the Risk Assessment and Mapping mitigation category.

***Risk to be mitigated** / problem to be addressed*

This risk assessment and mapping initiative provides BVES a summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment. The initiative performed modeling analysis of various historical, current, and future conditions to reflect ignition potential and structural loss through simulated fire events.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity

The development of risk-based maps enables BVES to improve its wildfire mitigations risk determination process. The development of a summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment enables BVES to significantly improve its wildfire mitigation decision-making process and resource allocation methodology. BVES recognizes that proper allocation of resources in wildfire mitigation planning requires significantly more granularity in its risk mapping capability showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment.

Alternatives
BVES could continue to rely on the CPUC Fire-Threat Map adopted in D. 17-12-024 December 14, 2017, for its service territory and its basic risk models. However, based on lessons learned from other utilities and industry best practices, development of a summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment will improve the wildfire mitigation planning process and its effectiveness.

Region prioritization *("where" to engage activity)*

The risk-based maps and models developed under this initiative cover the entire service area. All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

Progress on initiative

BVES hired a contractor to develop a fire model resulting in several high-resolution risk maps based on several characteristics of the service area and climate history/forecast. The modeling methodology and results are described in detail in **Section 4.5.1**.

In 2021, BVES spent $19,818.18 (OPEX) on this initiative.

In 2022, BVES plans to contract with an additional fire modeling firm to assist with future risk algorithms now that static results have been developed. While contracting is not yet finalized, BVES plans to continue the Risk Mapping Program and enhance modeling techniques that can be run independently of the consultant's support.

The RSE value for this initiative is 2.87. Projected spend (OPEX) is $30,000 in 2022, $30,900 in 2023, and $31,800 in 2024.

Future Improvements to Initiative

BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned to ensure a process of continuous improvement is applied to the initiative. Additionally, BVES will track piloted machine learning applications utilized by neighboring utilities to continue to refine the risk modeling and automation over the next five years.

<u>Technosylva Real-Time Modeling Support</u>
Ongoing development for the initiative program will be carried out by Technosylva over 2022. Utility risk forecasting will be supported by the Wildfire Analyst Enterprise (WFA-E) subscription and platform. This will provide BVES on-demand, real-time fire spread predictions and consequence impact analysis. Additionally, forecasting behavior for customer and service territory assets will take shape through daily weather prediction integration to support PSPS and response operations. The Wildfire Risk Reduction Model (WRRM) will provide asset risk analysis using historical weather climatology for future WMP planning.

The scope of work includes defining the risk domain for BVES's service area and utility asset data to review the terrain characteristics associated with fire spread with a 10-mile buffering around identified assets. Incorporating vegetation impacts will include surface and canopy fuels within the adjacent area of the buffer zones to enable review of conventional fire behavior, rate of spread, and flame length outputs deemed most common. Daily modeling and production of herbaceous and woody Live Fuel Moisture (LFM) data along with Dead Fuel Moisture (DFM) datasets. LFM and DFM are not typically included with weather wildfire risk forecasting data and are critical for accurate fire modeling and risk analysis. Historical data will provide insight on fire perimeters as it relates to the most recent and catastrophic wildfire events and landmarks and building infrastructure will also be mapped for highest risk consequence.

Risk Associated with Value Exposure (RAVE) data provides additional detailed data that describes the locational risk factors and susceptibility within the BVES domain area. This enhanced data includes risk factors such as social vulnerability and egress that can be used to adjust BVES risk outputs by incorporating the factors into risk calculations.

Specific areas within California with significant terrain features require a more detailed analysis of local wind situations that can occur to greatly affect wildfire spread. To address these requirements, higher resolution wind predictions are necessary, at 200-meter resolution, compared to conventional WRF wind predictions at 2 km. This data analytics subscription provides seamless integration with the USFS WindNinja[48] high resolution wind model to provide 200-meter wind data to support asset risk analysis and fire spread predictions.

Phase 1 deliverables will include:

WFA-E FireCast and FireSim Subscription

This annual software service includes FireCast (daily risk forecasting) and FireSim (on-demand fire spread prediction) applications configured for BVES input and output data.

FireCast includes electric utility assets and service territory risk outputs for all BVES distribution circuits. Inclusion of other assets will be determined based on need.

The platforms provide live daily risk forecasting analysis and on-demand fire simulation runs under current or forecasted conditions.

WFA-E WRRM Subscription

The WRRM data analysis and software integrates with Technosylva's 30-year climatology data to provide a detailed asset segment and equipment level analysis of risk for all assets. This may include poles and related equipment in addition to overhead distribution and transmission lines. Leveraging the historical risk analysis, the WRRM software integrates with asset Probability of Ignition (POI) data to calculate expected risk for all assets. Technosylva will work closely with BVES to identify possible sources for POI data should this data require development. Technosylva can derive an outage model with POI estimates, including RSE outputs.

WRRM is comprised of two deliverables:

This model provides a detailed analysis of risk using climatology data combined with wildfire spread simulations for calculating consequence metrics for possible asset ignitions.

Further, it encapsulates the WRRM results into a software application that facilitates review, query, filtering and exporting of the analysis results. The application can accommodate multiple WRRM analysis runs allowing for the historical tracking of risk over time on a per asset basis.

Weather Prediction Fire Data Subscription

Technosylva provides an advanced wildfire risk forecasting weather prediction data subscription. This data will be derived once daily at 2km spatial resolution and at an hourly temporal resolution. Each daily WRF forecast will be for 100 hours, providing the ability to forecast weather events

[48] USFS, U.S. Department of Agriculture, "WindNinja," https://www.firelab.org/project/windninja.

days in advance of them occurring. This is the same WRF data standard used by Investor-Owned Utilities (IOUs) in California.

LFM and DFM Data Subscription

The Technosylva LFM model uses remote sensing derived vegetation indices, extending methods to high resolution (30 m), to create two additional products required for fire behavior modeling (leveraging readily available Sentinel imagery and MODIS historical data).

Surface and Canopy Fuels Data Subscription

Technosylva will provide a custom developed detailed surface and canopy fuels dataset as part of the subscription. This will be updated with June 2022 as a starting point.

Building Loss Factor Data Subscription

Technosylva developed a new building-level loss factor metric (BLF). The BLF will allow fire simulations conducted with FireCast, FireSim and WRRM to now estimate the number of destroyed buildings. Previously, with WFA-E and WRRM only the number of buildings impacted (threatened) was calculated.

Phase 2 deliverables will include:

RAVE Data Subscription

WFA-E and WRRM analysis both derive metrics that associate risk with possible BVES asset ignition locations. This is referred to as Risk Associated with Ignition Locations (RAIL). Derived risk metrics are defined for BVES assets based on the consequence from possible asset ignited fires. The impact values are assigned back to the assets and are presented as baseline risk metrics in FireCast and WRRM. WFA-E FireCast uses daily weather forecasts while WRRM uses weather scenarios for benchmark days selected from climatology data (historical weather re-analysis).

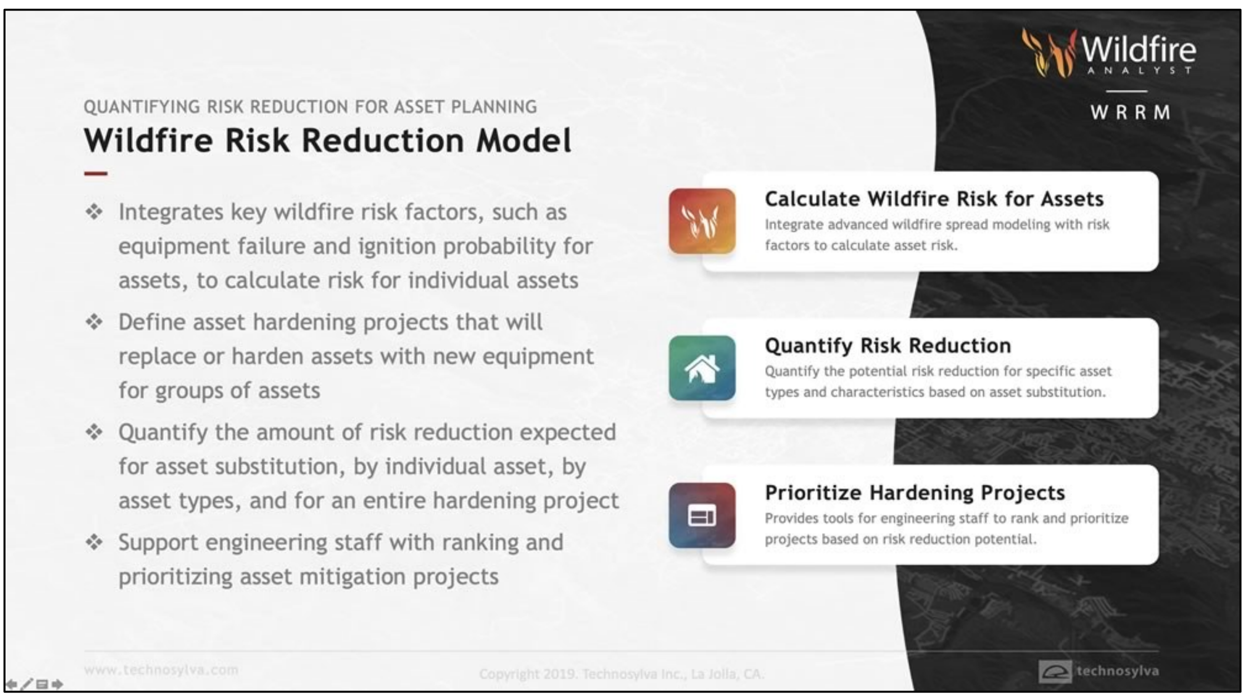
WindNinja High Resolution Wind Data Subscription

This will provide 200-meter wind field data for the entire BVES service territory that can be used in both FireCast and FireSim.

Validation of WindNinja and the BVES wildfire risk forecasting model output against BVES weather stations shall be performed jointly by Technosylva and BVES. Results of the verification will be documented to identify if the WindNinja improves or degrades forecast error. This will require close collaboration with the BVES team. Technosylva will also facilitate direct interaction with the USFS WindNinja Team on verification results.

Figure 7.3-1: Wildfire Risk Forecasting and Monitoring Approach

Figure 7.3-2: Wildfire Risk Reduction Model Approach



7.3.1.2 Climate-driven risk map and modeling based on various relevant weather scenarios

Initiative activities **7.3.1.1**, **7.3.1.2**, **7.3.1.3**, **7.3.1.4**, and **7.3.1.5** are included as part of the **Risk Mapping Program**. BVES considers one major program that addresses all aspects of the Risk Assessment and Mapping mitigation category.

Risk to be mitigated */ problem to be addressed*

This risk assessment and mapping initiative will provide a more granular depiction of climate-driven risk based on various relevant weather scenarios using localized weather data in the BVES service area. The initiative focuses on development and use of tools and processes to estimate incremental risk of foreseeable climate scenarios, such as drought, across portions of the grid (or more granularly, e.g., circuit, span, or asset).

Initiative selection *("why" engage in activity)*

"why" engage in activity
The development of climate-driven risk maps and modeling based on various relevant weather scenarios will enable BVES to significantly improve its wildfire mitigation decision-making process and resource allocation methodology. BVES recognizes that proper allocation of resources in wildfire mitigation planning requires significantly more granularity in its climate-driven risk maps and modeling based on various relevant weather scenarios capability.

Alternatives
BVES could continue to rely on countywide weather data along with fuel inventory reports through public avenues to measure fire risk. Development of climate-driven risk maps and modeling based on various relevant weather scenarios is known from industry experience and lessons learned to improve the wildfire mitigation planning process and its effectiveness.

Region prioritization *("where" to engage activity)*

The risk-based maps and models developed under this initiative cover the entire service area. All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES's service area as it is necessary to gain a full appreciation of the current state and changing nature of risks throughout the HFTD 2 and HFTD 3 areas.

Progress on initiative

BVES hired a contractor to develop a fire model resulting in several high-resolution risk maps based on several characteristics of the service area and climate history/forecast. The modeling methodology and results are described in detail in **Section 4.5.1**. The model provided insight into the anticipated conditions in 2050 due to climate change.

In 2021, BVES spent $19,376.62 (OPEX) on this initiative.

In 2022, BVES plans to contract with an additional fire modeling firm to assist with future risk algorithms now that static results have been demonstrated. While contracting is not yet finalized, BVES plans to continue the Risk Mapping Program and enhance modeling techniques that can be run independently of the consultant's support.

The RSE value for this initiative is 2.87. Projected spend (OPEX) is $8,200 in 2022, $8,400 in 2023, and $8,700 in 2024.

Future improvements to initiative

Details on the program's 2022 scope of work are conveyed above in **Section 7.3.1.1**.

Once the initiative is developed and implemented, BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for future WMP updates. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative. BVES will likely revisit updating the climate model in five years to keep a long-term view of the anticipated ignition risks due to climate change.

7.3.1.3 Ignition probability mapping showing the probability of ignition along the electric lines and equipment

Initiative activities **7.3.1.1**, **7.3.1.2**, **7.3.1.3**, **7.3.1.4**, and **7.3.1.5** are included in the **Risk Mapping Program**. BVES considers one major program that addresses all aspects of the Risk Assessment and Mapping mitigation category.

***Risk to be mitigated** / problem to be addressed*

This risk assessment and mapping initiative will provide BVES ignition probability mapping showing the probability of ignition along the electric lines and equipment. The initiative focuses on development and use of tools and processes to assess the risk of ignition across regions of the grid (or more granularly, e.g., circuits, spans, or assets).

The work product executed in 2021 includes a map and underlying model data that illustrates ignition probability using criteria such as the flame length, predicted behavior, and burning index as it may be impacted by utility assets.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
The development of ignition probability mapping showing the probability of ignition along the electric lines and equipment will enable BVES to significantly improve its wildfire mitigation decision-making process and resource allocation methodology. BVES recognizes that proper allocation of resources in wildfire mitigation planning requires significantly more granularity in its risk mapping capability for ignition probability mapping showing the probability of ignition along the electric lines and equipment.

Alternatives
BVES could continue to rely on the CPUC Fire-Threat Map adopted in D. 17-12-024 December 14, 2017, for its service territory and its basic risk models. However, based on lessons learned from other utilities and industry best practices, development of ignition probability mapping showing the probability of ignition along the electric lines and equipment will improve the wildfire mitigation planning process and its effectiveness.

***Region prioritization** ("where" to engage activity)*

The risk-based maps and models developed under this initiative cover the entire service area. All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES's service area as it is necessary to gain a full appreciation of the current state and changing nature of risks throughout the HFTD 2 and HFTD 3 areas.

Progress on initiative

BVES hired a contractor to develop a fire model resulting in several high-resolution risk maps based on several characteristics of the service area and climate history/forecast. The modeling methodology and results are described in detail in **Section 4.5.1**.

In 2021, BVES spent $18,051.95 (OPEX) on this initiative.

In 2022, BVES plans to contract with an additional fire modeling firm to assist with future risk algorithms now that static results have been demonstrated. While contracting is not yet finalized, BVES plans to continue the Risk Mapping Program and enhance modeling techniques that can be run independently of the consultant's support.

The RSE value for this initiative is 2.87. Projected spend (OPEX) is $28,200 in 2022, $29,000 in 2023, and $29,900 in 2024.

Future improvements to initiative

Details on the program's 2022 scope of work are conveyed above in **Section 7.3.1.1**.

Once the initiative is developed and implemented, BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for a future WMP update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative.

7.3.1.4 Initiative mapping and estimation of wildfire and PSPS risk-reduction impact

Initiative activities **7.3.1.1**, **7.3.1.2**, **7.3.1.3**, **7.3.1.4**, and **7.3.1.5** are included in the **Risk Mapping Program**. BVES considers one major program that addresses all aspects of the Risk Assessment and Mapping mitigation category. ***Risk to be mitigated*** */ problem to be addressed*

This risk assessment and mapping initiative will provide BVES initiative mapping and estimation of wildfire and PSPS risk-reduction impact. While BVES has not yet had to initiate a PSPS activation, maintaining preparations and weather monitoring is crucial to ensuring PSPS protocol efficacy. This initiative focuses on development of a tool to estimate the risk reduction impact (for both wildfire and PSPS risk) and risk-spend efficiency of various initiatives.

Initiative selection *("why" engage in activity*

"why" engage in activity
The development of initiative mapping and estimation of wildfire and PSPS risk-reduction impact will enable BVES to significantly improve its wildfire mitigation decision-making process and resource allocation methodology. BVES recognizes that proper allocation of resources in wildfire mitigation planning requires significantly more granularity in its capability for initiative mapping and estimation of wildfire and PSPS risk-reduction impact. BVES has not met target thresholds for a PSPS activation to

date but remains prepared to initiate protocols such that these triggers arise. Retaining real-time mapping and modeling capabilities will ensure granular monitoring and assist in PSPS decision making.

Alternatives

BVES could continue to rely on the CPUC Fire-Threat Map adopted in D.17-12-024 on December 14, 2017 for its service territory and its basic risk models. However, based on lessons learned from other utilities and industry best practices, development of initiative mapping and estimation of wildfire and PSPS risk-reduction impact will improve the wildfire mitigation planning process and its effectiveness.

Region prioritization *("where" to engage activity)*

The risk-based maps and models developed under this initiative cover the entire service area. All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES's service area as it is necessary to gain a full appreciation of the current state and upcoming initiatives across BVES's service areas.

Progress on initiative

BVES hired a contractor to develop a fire model resulting in several high-resolution risk maps based on several characteristics of the service area and climate history/forecast. The modeling methodology and results are described in detail in **Section 4.5.1**.

In 2021, BVES spent $17,389.61 (OPEX) on this initiative.

In 2022, BVES plans to contract with an additional fire modeling firm to assist with future risk algorithms now that static results have been demonstrated. While contracting is not yet finalized, BVES plans to continue the Risk Mapping Program and enhance modeling techniques that can be run independently of the consultant's support.

The RSE value for this initiative is 2.87. Projected spend (OPEX) is $27,500 in 2022, $28,300 in 2023, and $29,200 in 2024.

Future improvements to initiative

Details on the program's 2022 scope of work are conveyed above in **Section 7.3.1.1**.

Once the initiative is developed and implemented, BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for a future WMP update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative.

7.3.1.5 Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment

Initiative activities **7.3.1.1**, **7.3.1.2**, **7.3.1.3**, **7.3.1.4**, and **7.3.1.5** are included in the **Risk Mapping Program**. BVES considers one major program that addresses all aspects of the Risk Assessment and Mapping mitigation category.

Risk to be mitigated */ problem to be addressed*

This risk assessment and mapping initiative will provide BVES match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment. The initiative focuses on development and use of tools and processes to assess the impact of potential ignition and risk to communities (e.g., in terms of potential fatalities, structures burned, monetary damages, area burned, impact on air quality and greenhouse gas, or GHG, reduction goals, etc.).

This simulation method will enable BVES to conduct more precise mapping and modeling of ignition risk potential.

Initiative selection *("why" engage in activity)*

"why" engage in activity
The development of match drop simulations showing the potential wildfire consequence of ignitions occurring along the electric lines and equipment will enable BVES to significantly improve its wildfire mitigation decision-making process and resource allocation methodology. BVES recognizes that proper allocation of resources in wildfire mitigation planning requires significantly more granularity in its capability for match drop simulations.

Alternatives
BVES could continue to rely on the CPUC Fire-Threat Map adopted in D.17-12-024 on December 14, 2017 for its service territory and its basic risk models. However, based on lessons learned from other utilities and industry best practices, development of match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment will improve the wildfire mitigation planning process and its effectiveness.

Region prioritization *("where" to engage activity)*

The risk-based maps and models developed under this initiative cover the entire service area. All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES's service area as it is necessary to gain a full appreciation of the current state and changing nature of risks throughout the HFTD 2 and HFTD 3 areas.

Progress on initiative

BVES hired a contractor to develop a fire model resulting in several high-resolution risk maps based on several characteristics of the service area and climate history/forecast. The modeling methodology and results are described in detail in **Section 4.5.1**.

In 2021, BVES spent $17,610.39 (OPEX) on this initiative.

In 2022, BVES plans to contract with an additional fire modeling firm to assist with future risk algorithms now that static results have been demonstrated. While contracting is not yet finalized, BVES plans to continue the Risk Mapping Program and enhance modeling techniques that can be run independently of the consultant's support.

The RSE value for this initiative is 2.87. Projected spend (OPEX) is $27,700 in 2022, $28,600 in 2023, and $29,400 in 2024.

Future improvements to initiative

Details on the program's 2022 scope of work are conveyed above in **Section 7.3.1.1**.

Once the initiative is developed and implemented, BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for a future WMP update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative.

7.3.2 Situational Awareness and Forecasting

Initiatives to improve situational awareness and forecasting are paramount to monitor and react to weather events across BVES's 32-square mile service area.

BVES uses the NFDRS, which provides useful information for fuel, moisture, and related fire weather conditions. However, the reports are presented at the county level. San Bernardino County is the largest county in the U.S. with extreme variability across the county, from lowland conditions at or slightly below sea level to mountainous terrain exceeding 11,500 feet which creates numerous unique microclimates. Consequently, actionable data is not always readily available from the reports because BVES covers just a small part of the county.

To provide more granular monitoring of actual conditions, BVES has selected a series of programs and initiatives to enhance its situational awareness of its service area climatology and forecasted meteorological events.

Information Requirements & Methods: Critical information to BVES's wildfire mitigation decision making includes weather conditions (forecasted and actual), system line-up, and available resources. This information is best gathered from devices such as weather stations, HD Cameras, and other sensors in the field. Online feeds and websites, such as the NFDRS rating system information and weather feeds, also provide highly useful information resources to BVES. Future initiatives will include real-time, on-demand weather and risk forecasting capabilities through sophisticated algorithms and network platforms.

Roles & Responsibilities: Key Field Operations staff have real-time access to situational awareness information to inform decision making and operations. These staff members include the Utility Manager, Field Operations Supervisor, Utility Engineer and Wildfire Mitigation Supervisor, GIS Analyst, and Service Crew/Dutyman. Additionally, the Customer Service Supervisor is included to ensure customers and key stakeholders are informed as applicable.

Methods of Sharing Information: Situational awareness information is shared through network-connected devices such as supervisory control and data acquisition (SCADA) operations displays at BVES, desktop computers, laptops, and mobile devices out in the field. Access to situational awareness products on mobile devices is particularly helpful to achieving 24/7 situational awareness.

Implementation of Technologies to Communicate and Manage Information: Technologies that aid in communicating situational awareness information include SCADA displays (including incorporation of weather station data into SCADA), social media, and other networked solutions.

The following initiatives are categorized under situational awareness and forecasting.

7.3.2.1 Advanced weather monitoring and weather stations

The **Weather Station Installation Program** initiative relates to planned installation of utility-owned weather stations. All planned weather stations were installed as of 2021.

Risk to be mitigated */ problem to be addressed*

This initiative intends to provide awareness of the microclimates that exist adjacent to electrical assets and understand real-time risk drivers during hazardous weather conditions. Additionally, this program enhances data collection, recording, and analysis for weather-related impacts paired with external, public meteorological resources.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Weather stations are a key component in situational awareness and wildfire risk-mitigation strategies. In 2021, BVES completed the installation of all 20 weather stations manufactured by Orion. These stations measure temperature, relative humidity, barometric pressure, wind direction and speed, and precipitation.

These sensors communicate over wireless cellular communications to help BVES obtain service territory-specific data and information at one-minute interval recordings. BVES intends to integrate the output of these weather stations to SCADA to concentrate critical information in one primary display and to provide alarm and notification capability.

BVES asserts a total of 20 weather stations will provide sufficient coverage of its 32 sq. mi. service area. This determination was made in consultation with BVES's weather consultant.

Alternatives
BVES considered alternatives as part of the planning before the initiative began. BVES historically relied on county-wide of meteorological and fuel condition data (NFRDS, RFW and HWW issuances, etc.), which does not provide sufficient granularity for BVES's 32-sq. mi. service area. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

Region prioritization *("where" to engage activity)*

All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES's service area as it is necessary to gain a full appreciation of the real-time conditions and risk status throughout the HFTD 2 and HFTD 3 areas. Therefore, the weather stations are strategically placed across the region for optimal surveillance. A map of the installed deployments is captured below.

Figure 7.3-3: BVES Installed Weather Stations

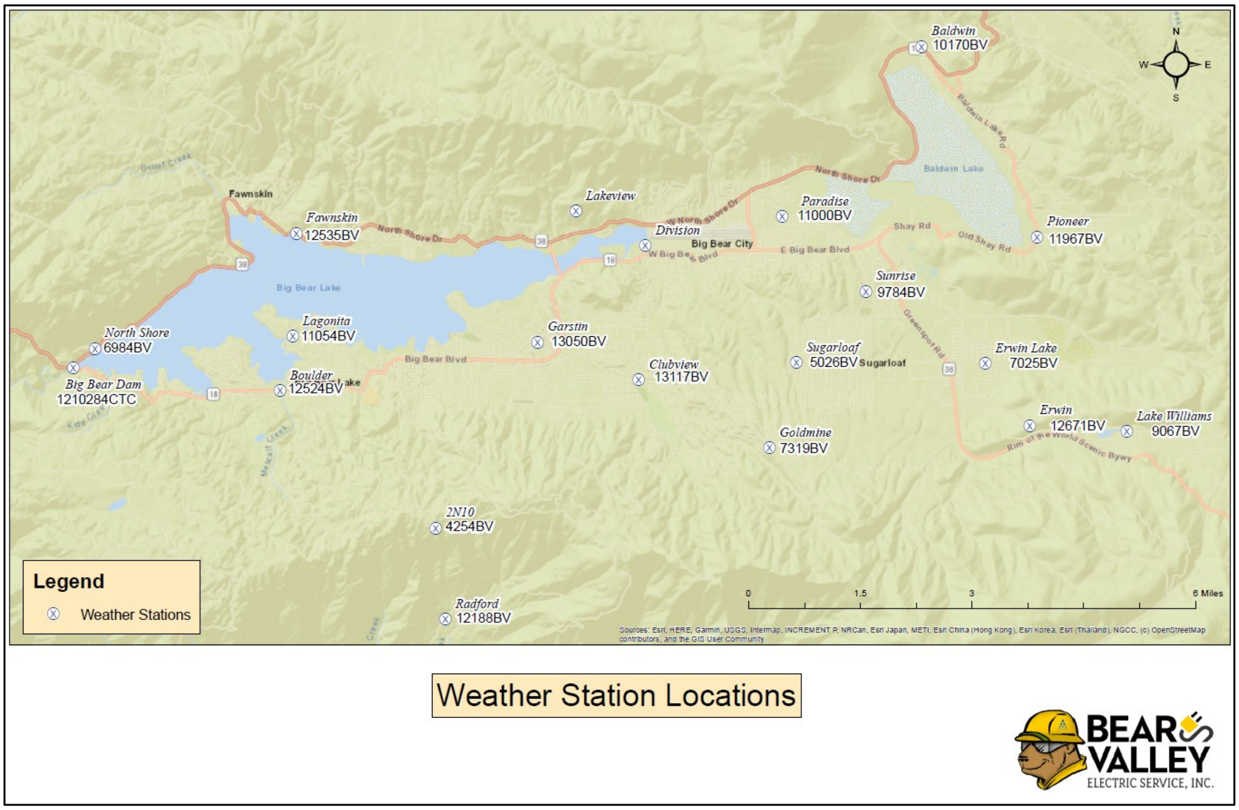


Table 7.3-1: BVES Advanced Weather Monitoring and Station Location Detail

Weather Station Name	Pole Number	Year of Installation	Latitude	Longitude
Big Bear Dam	1210284CTC	2020	34.24227667	-116.97761740
North Shore	6984BV	2019	34.24532883	-116.97341180
Fawnskin	12535BV	2020	34.26380082	-116.93446430
Division		2020	34.26186422	-116.86659300
Paradise	11000BV	2020	34.26652527	-116.84013820
Baldwin	10170BV	2020	34.29375365	-116.81310840
Pioneer	11967BV	2019	34.26318578	-116.79065270
Erwin Lake	7025BV	2020	34.2429703	-116.8006365
Erwin	12671BV	2019	34.23298191	-116.79211290
Lake Williams	9607BV	2020	34.23198312	-116.77332380
Sunrise	9784BV	2019	34.25554307	-116.82382920
Sugarloaf	5026BV	2020	34.24301379	-116.83739720
Clubview	13117BV	2019	34.24027965	-116.86800240
Goldmine	6940BV	2019	34.232107	-116.845663
Garstin	13050BV	2019	34.24588032	-116.88580580
Boulder	12524BV	2019	34.2386084	-116.9376263
Lagunita	11054BV	2019	34.24732716	-116.93515330
2N10	4254BV	2021	34.209833	-116.904333
Radford	12188BV	2019	34.20184	-116.90551
Lake View		2021	34.267380,	-116.880145

Progress on initiative *(amount spent, regions covered) and plans for next year*

In 2021, BVES spent $82,164.00 (CAPEX) on this initiative.

BVES's entire service area (HFTD Tier 2 and 3) is covered by the initiative. All 20 weather stations are now deployed with the final two integrated in 2021. In 2022, BVES expects to apply the results of this initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update. Ongoing monitoring of these devices support on-demand situational awareness of the territory.

The RSE value for this initiative is 10.45. Projected spend related to maintaining, operating, and integrating the weather stations will be (OPEX) $3,700 in 2022, $3,800 in 2023, and $3,900 in 2024.

It is BVES's intent to utilize the weather stations to alert BVES staff on high wind conditions and assist the BVES weather consultant in forecasting.

Future improvements to initiative

BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative. Additionally, with Technosylva in 2022, BVES will seek to automate some of its risk assessment mapping to incorporate near real-time weather data and provide more accurate and timely assessments of wildfire risk. These risk maps will be automated and pushed to BVES key staff involved in PSPS preparations and decision making.

BVES will consult with Technosylva to determine if the current array of 20 weather stations is sufficient or if Technosylva has any additional recommendations for new weather stations or to relocate an existing weather station.

7.3.2.2 Continuous monitoring sensors

This initiative covers the **ALERTWildfire Camera Installation Program** and the **Online Diagnostic System Pilot**.

7.3.2.2.1 ALERTWildfire Camera Installation Program

Risk to be mitigated */ problem to be addressed*

This initiative intends to provide visual awareness into the territories adjacent to electrical assets and maintain live accounts of risk drivers during hazardous weather conditions. The cameras owned by BVES will also contribute to the southern California system, which comprises a shared network of utility, academic, and fire response cameras to provide coverage of live feeds to monitor conditions and assist emergency event awareness.

Initiative selection *("why" engage in activity)*

"why" engage in activity

In partnership with the University of California San Diego (UCSD), CAL FIRE, and Big Bear Fire Department, BVES is installing an ALERT Wildfire HD Camera System to monitor the service area and surrounding areas for fire and immediately alert fire fighting assets. HD camera locations were selected at a joint meeting with UCSD, CAL FIRE, Big Bear Fire Department and BVES. Cameras are currently installed at the top of Bear Mountain, Snow Summit, and “Deadman’s Ridge” (Lake Williams). BVES is coordinating the installation of cameras at the other two locations (Bertha Peak and KBHR antenna). BVES was collaborative and deliberate in siting its cameras, which are sufficient and ideally situated to surveil a broad area to identify oncoming threats from surrounding forest areas. During high threat conditions, BVES deploys personnel to supplement camera information with observations by qualified personnel.

Alternatives

There is presently no alternative or cameras owned by others that BVES can use for this function. Alternatives were considered as part of the planning process as discussed within the BVES 2020 WMP.

Region prioritization *("where" to engage activity)*

BVES’s service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES’s small service area in a prioritized manner, is minimal. Additionally, BVES’s HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. This effort will cover the entirety of BVES’s service area as it is necessary to gain a full appreciation of the real-time conditions throughout the HFTD 2 and HFTD 3 areas. Therefore, the wildland HD cameras are strategically placed across the region for optimal surveillance.

As mentioned above, HD camera locations were selected at a joint meeting with UCSD, CAL FIRE, Big Bear Fire Department and BVES.

Progress on initiative

In 2021, BVES installed the final two cameras in Bertha Peak and on the KBHR antenna. The KBHR antenna is within the Baldwin Lake area. BVES had seven existing cameras prior to 2021 on the ridgeline southwest area of the service territory and two in the southeast corner on “Deadman’s Ridge” near Lake Williams. BVES spent $53,715.00 (CAPEX) on this initiative in 2021. BVES finds the coverage of the territory to be optimal, especially in areas of high risk or Tier 3.

There is a total of 15 cameras in 7 key locations providing complete surveillance coverage of the BVES service areas. No additoional HD camera installions are scheduled for 2022 BVES is coordinating with UCSD and will support any upgrades or no camera installations deemed necessary by the ALERTWildfire Program. Currenlty, none are planned.BVES’s entire service area (HFTD Tier 2 and 3) is covered by the initiative. In 2022, BVES expects to apply the results of this initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update.

The RSE value for this initiative is 31.27. There is no projected spend budgeted for years 2022, 2023, or 2024.

Future improvements to initiative

BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for it 2023 WMP Update. BVES will work with its partners (USSD, CAL FIRE, Big Bear Fire Department, etc.) to monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative. Additionally, BVES works closely with UCSD and will support any camera upgrades or additional camera installations. Currently, no upgrades or additional camera installations are planned by UCSD for the ALERTWildfire system in BVES’s service area.

7.3.2.2.2 Online Diagnostic System Pilot

***Risk to be mitigated** / problem to be addressed*

This initiative intends to mitigate the potential for fire exposure of high-risk circuits not poised to be replaced with covered conductors in the immediate future, due to the current program schedule or other constraints. Any risk exposure to bare wires is addressed by this initiative.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
This project installs continuous monitor sensors to provide usable grid insight information that is measured, reported, and documented. Analytics help to ensure that current and future irregularities can be corrected before a problem arises. This will help to ensure safety, reliability, cost control, and customer satisfaction. The system is designed to pinpoint irregularities, which may be due to degrading/imminent hardware failures, as well as identify objects such as vegetation contacting the lines. This will assist BVES in rapidly inspecting potential problems before they develop into an ignition source.

Alternatives
There are presently no alternatives considered that are viable for BVES's initiative needs. Until covered wire deployments can be made at a significant scale, this initiative will fulfill gap surveillance issues to help to ensure the entire system is hardened and mitigated from potential ignition risk.

***Region prioritization** ("where" to engage activity)*

BVES's entire service area is in Tier 2 and Tier 3 high risk wildfire service areas. Monitoring sensors will be strategically placed across the region on bare wire conductors that are not in the queue for hardening. BVES will target circuits that will not be hardened over the next 3-5 years. The intent is to deploy this mitigation on circuits that will remain bare wire for a significant period of time. This strategy is intended to complement the covered wire program and assist deploying wildfire mitigation on bare wire circuits as soon as feasible.

Progress on initiative

This is a new initiative in 2022. The pilot will be executed over 2022 with one circuit receiving installation of the monitoring sensors. The selected circuit is the Pioneer Circuit. This circuit was selected for several reasons:

- The circuit meets the criteria of being a bare wire circuit that will not be replaced with covered wire for at least 3-5 years.
- The circuit is a medium risk circuit, borderline high-risk circuit
- The circuit has attributes that will make executing the pilot program less challenging allowing the focus to be on the diagnostic equipment. The attributes are:
  - Easy and ready connectivity to the fiber network for the monitoring equipment.
  - Relatively easy access to the monitoring equipment for installation, maintenance, and follow-up testing visits.

Approximate cost in 2022 (CAPEX) is $75,000. The RSE value for this initiative is 15.28.

The EGM Meta-Alert System Solution will allow grid operators to maintain surveillance of this pilot circuit. The network supports a large number of sensors that can operate in real-time and meet most of the global communication standards and requirements. Additional features include independently gathering field data from installed sensors and other devices with sensor-to-sensor communication, and the ability to transfer operational commands from the server to the sensors. The EGM Meta-Alert System communication utilizes a bi-directional, dual-layer system for communication from installed sensors to the Meta-Alert Management System. System functionality includes:

1. Advance trouble notification related to fire, grounding, or third-party impact
2. Accurate measurements within 50 feet of the fault location
3. Redundant mesh communication capabilities
4. Ability to work on all grounding modes
5. Advanced analytics output for a wide variety of control room applications, including renewables integration, microgrids, electrical vehicle chargers, and energy storage devices
6. Above and below-ground systems
7. User defined alerts, display, and GIS schematic presentation for exportable data via the interfaces
8. Ability to run queries and reports with operational data archiving
9. Remote firmware upgrades
10. Device deployment communication planning tool
11. Price competitiveness to reduce the utility's cost of ownership

Future improvements to initiative

BVES expects to apply the results of the pilot initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update. BVES will evaluate the pilot based on specific criteria, including the following:

- Ease of installation.
- Number of false positives (alarms).
- Number of missed alarms.
- Ease of operation for staff to monitor the system.
- Ability for IT staff to maintain the equipment and associated software.
- Technical support from the contractor (EGM).
- Durability of the field equipment exposed to the BVES environment (snow, ice, etc.).
- Equipment operating reliability.

Once the pilot project equipment is installed and operational, BVES will begin the evaluation period. BVES expects the pilot equipment to be installed no later than October 2022. BVES will evaluate the system for approximately six months. At the end of the six months, in addition to reviewing the performance of the system, BVES will determine if the six-month pilot evaluation period was successful or if additional evaluation is needed.

BVES is developing a prioritized list of circuits to install the system on if the pilot project is deemed successful. This list will be included in BVES's 2023 WMP and will include the following information: circuit name, risk level (by fire safety matrix), and diagnostic equipment schedule.

7.3.2.3 Fault indicators for detecting faults on electric lines and equipment

This initiative covers the **Situational Awareness Hardware Program // Fault Indicator Installation Project**.

Risk to be mitigated */ problem to be addressed*

This initiative is part of ongoing, routine work to address when a Fault Indicators (FIs) device is appropriate and necessary for installation as well as maintenance of the devices. This program supports early detection and remediation of circuit faults, reducing deployment and restoration time.

Initiative selection *("why" engage in activity)*

"why" engage in activity

The installation of fault indicators allows BVES to reduce risk of ignition or spark from having the ability to disable reclosers during high-risk conditions. Further, fault indicators narrow the affected area of line allowing for rapid response in remediation activities. BVES has 110 fault indicators installed in the system and intends to install an additional 129 over 2022 and 2023.

BVES has installed FIs at key locations to reduce the time it takes to locate faults; thereby, reducing the time to isolate faults from the system or correcting the damage. This has the effect of reducing the possibility of an ignition developing into a fire that may spread into a wildfire. Prior to the start of the program, BVES had 110 FIs installed in its system at key locations. As part of the WMP, BVES will install an additional 129 FIs at 39 key locations to provide optimal FI coverage in the system in 2022 and 2023.

Alternatives:

BVES considered alternative designs for line construction and device management as part of the planning before the initiative began. There are no currently viable alternatives to providing precautionary or advanced action to mitigating sparking and arcing risk. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

Alternatives would include enhanced technologies for fault detection and response, which are reviewed each year as other utilities showcase successful investigation and pilot deployments.

Region prioritization *("where" to engage activity)*

BVES's entire service area is in Tier 2 and Tier 3 HFTDs. BVES's service area is small (32 square miles); therefore, the marginal expense of targeting subareas within BVES's small service area in a prioritized manner, is minimal. Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. BVES will advance this initiative by prioritizing the highest risk circuits which are appropriate for deploying this technology.

Progress on initiative

BVES has no reported spend on this initiative in 2021.

BVES is planning to enhance its fault detection capability by adding additional equipment in 2022 and 2023. BVES continues to monitor advanced technologies. Over the period of 2022 and 2023, BVES will install SCADA-capable FIs in its system as indicated in the following table:

Table 7.3-2: SCADA Capable FI Instillation Plan

Circuit	Voltage (kV)	Circuit Length (Circuit Miles)	Number of FIs to Install (SCADA capable)	Locations
Shay	34	17.56	12	4
Baldwin	34	9.44	9	3
North Shore	4	23.92	6	2
Erwin Lake	4	29.24	6	2

Clubview	4	10.45	6	2
Goldmine	4	18.46	9	3
Paradise	4	11.85	12	4
Sunset	4	11.17	15	5
Sunrise	4	11.65	9	3
Holcomb	4	14.1	6	2
Eagle	4	8.91	18	6
Garstin	4	8.91	9	3
Interlaken	4	10	6	2
Country Club	4	4.12	6	2

The selected locations will improve the ability of crews to locate and isolate faults on these circuits. It should be noted that BVES has 110 FIs installed in its system. This project is intended to build upon what has already been installed for that whenever a fault occurs, BVES crews have indicators on where to search for the fault.

The RSE value for this initiative is 4.13. Projected spend (CAPEX) is $263,300 in 2022 and $282,100 in 2023. There is no budgeted amount for 2024.

Future improvements to initiative

BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative. This program maintains constant reevaluation of need and includes a two-year installation schedule for 2022 and 2023. BVES will be especially vigilant on how well the FIs work in SCADA and how that adds efficiency to fault localization before a truck is ever rolled to the field. If successful, BVES will review its FIs system and consider further expansions.

7.3.2.4 Forecast of a fire risk index, fire potential index, or similar

This initiative covers the **Weather Consultant // Fire Risk Index Activity** for ongoing fire risk weather forecasting.

Risk to be mitigated */ problem to be addressed*

This initiative aims to use a combination of weather parameters (such as wind speed, humidity, and temperature), vegetation and fuel conditions, and other factors to determine current fire risk and to create a forecast potential indicative of a fire risk. A sufficiently granular index would inform operational decision-making. BVES has not historically used a fire potential index though it operates with caution during high fire risk conditions and modifies operational activities performed in the field accordingly. BVES does maintain situational awareness through its contracted weather consultant and consultation with the NFDRS reports. On-demand weather analysis and forecasting capabilities will further be developed in 2022 through BVES's engagement with Technosylva.

Initiative selection *("why" engage in activity)*

"why" engage in activity

BVES monitors its weather stations and several web-based weather resources to evaluate forecasted weather and monitor for potential extreme fire conditions. The weather resources monitored by BVES are products produced by the NWS, local weather forecasts from local media, and the NFDRS 7-day significant fire potential product. The NFDRS is monitored at least daily by Field Operations. BVES also monitors the likelihood of dry lightning occurrence as it is the type most likely to cause wildfires. This initiative is in place.

Alternatives

This initiative is ongoing. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible. BVES will be considering the development of a formalized fire potential index through the initiative process listed in **Section 7.3.1.**

Region prioritization *("where" to engage activity)*

BVES's entire service area is in Tier 2 and Tier 3 high risk wildfire service areas. Variations in localized climates affect the weather coverage across the service territory and the county through RFW and HWW notifications. Therefore, in addition to deploying an array of 20 weather stations across BVES's 32-square mile service area, BVES has engaged a weather consultant experienced in San Bernardino Mountain weather. BVES's service area is only a small portion of San Bernadino County which means that typical forecast tools are imprecise, but the consultant is able to provide a forecast for the service area in a short period of time pointing out exactly which areas are expected to have high wind gusts and sustained winds. BVES also utilizes the NFDRS system to assess the dryness and fuel availability that creates dangerous fire conditions. However, during a high fire threat weather event, the consultant will pay particular attention to the "high risk" areas BVES has designated for potential PSPS and the consultant will also focus on the areas where winds (sustained and/or gusts) are particularly high.

Technosylva will initially direct its efforts on building a model to forecast fire threat potential and spread throughout the BVES system. As noted above, BVES's service area and circuits are small and there is little efficiency to be gained by prioritizing one area over another when developing the model. Once the model is developed and implemented, the higher fire threat and spread areas will be prioritized in the monitoring for possible PSPS.

Progress on initiative

In 2021, BVES spent $12,700 (OPEX) on this initiative. This project is an ongoing initiative.

BVES maintains use of its contracted meteorologist and local forecast observations for field planning activities and fire weather watch. As demonstrated by other utilities, BVES finds that real-time access to this data is pertinent to help to ensure that daily activities are performed under the greatest amount of caution. BVES's entire service area (HFTD Tier 2 and 3) is covered by the initiative. In 2022, BVES expects to apply the results of this initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update.

BVES has an effective system in place to evaluate high risk fire threat weather through its weather consultant, using the NFDRS, and real-time wind speed (sustained and/or gusts). In 2022 BVES will continue to refine this process and improve the dissemination of fire threat weather to additional staff.

Additionally, BVES is working with Technosylva to implement a more robust fire threat prediction and fire spread model that will provide BVES near real-time assessment of the fire threat along its circuits. The product will superimpose a color coded "heat map" on BVES's circuit maps in a GIS overlay. The heat map will indicate the degree of wildfire risk at any point on BVES's circuits through the gradients of the color coding (red being highest risk and blue being lowest risk) to assist BVES in its PSPS decision making process.

The RSE value for this initiative is 20. Projected spend (OPEX) is $13,000 in 2022, $13,500 in 2023 and $13,900 in 2024.

Future improvements to initiative

This project will be enhanced by the risk map and model development planned in 2022, which is captured in **Section 7.3.1.**

BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation for its 2023 WMP Update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative.

As Technosylva's models are implemented, BVES will re-evaluate the role of its weather consultant and use of NFDRS in its PSPS decision making process. This evaluation will be done in 2023.

7.3.2.5 Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions

This initiative covers **Personnel Sufficiency // High Risk Conditions Protocols.** This also addresses costs associated with the assigned Wildfire Response Team.

Risk to be mitigated */ problem to be addressed*

This initiative is part of ongoing work to address personnel needs during high-risk conditions. BVES will continue to assess the need for additional resources as deemed necessary. Currently, during high fire threat weather conditions, BVES will deploy Line Crews and engineering staff to the field in the higher risk areas experiencing high winds (sustained and/or gusts). These personnel are equipped with wind gauges and monitor for potential unsafe conditions such as "blow-ins", "wire slap", "tree and large branch sway", and other issues that may cause an ignition. BVES can easily deploy 10 wildfire response teams (WRTs), but in most cases would likely only need to deploy 3-4 teams. Should more than 10 WRTs be required, BVES would exercise its emergency contract with a power line company with assets and crews in Big Bear Lake or in the vicinity of Big Bear Lake. Additionally, BVES would seek CUEA mutual assistance, if necessary to support the WRTs.

This activity is also reflected in work described in grid operations and protocols.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES must position personnel within the service area to monitor system conditions and weather on site and quickly respond to emerging conditions. Field observations will inform operational protocols when high risk conditions are reported. Due to factors such as "blow-ins", actual conditions may be worse before BVES's PSPS wind threshold is met, in which case it is vital to get the WRTs' assessment of the situation so that BVES may ensure public safety during high fire threat weather.

Alternatives
Additional resources for field operations are routinely considered as needs arise. BVES also maintains memorandums of understanding (MOUs) with nearby fire support in the event of a small ignition for quick suppression.

Region prioritization *("where" to engage activity)*

BVES's entire service area is in Tier 2 and Tier 3 HFTDs. Therefore, available resources are determined based on the work scope and operational condition criteria. Based on the localized wind forecasts, as well as actual observed wind conditions on BVES's 20 weather stations across its 32 square mile service area, BVES will determine the optimal deployment of the WRTs.

Progress on initiative

BVES deploys crews as necessary, has emergency contracts in place, and has signed on to mutual assistance agreements. There are no costs reflected under this initiative for 2021 due to no deployments of the WRTs. The activities performed reflect normal business operations. In June of 2022, BVES conducted a functional exercise in which it deployed WRTs. BVES plans to conduct training for WRTs in September 2022.

However, as part of BVES's remapping of initiatives and costs for 2022, the utility has budgeted (OPEX) $11,500 in 2022, $11,900 in 2023, and $12,300 in 2024.

Future improvements to initiative

BVES continuously assesses personnel deficiencies and additional roles to support field operations. BVES will continue to improve its training for the WRTs through classroom training, hands-on training in the field, and conducting functional exercises.

Should a PSPS be invoked, BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative. Additionally, BVES will look to other utilities' lesson learned for WRTs.

7.3.2.6 Weather forecasting and estimating impacts on electric lines and equipment

This initiative covers the **Weather Consultant // Weather Forecasting** for ongoing fire risk weather forecasting.

Risk to be mitigated */ problem to be addressed*

This initiative intends to develop a methodology for forecasting weather conditions relevant to utility operations. This includes monitoring meteorological changes and analyses to incorporate into utility decision-making. This will also help build a baseline of high-risk drivers and help eliminate false positive events or false negative forecasts for potential PSPS activations.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES contracts with a meteorolgist to provide at least weekly focused weather forecasts tailored to BVES's service area evaluating the prevailing fire threat. The meteorolgist is able to obtain analysis of weather data before, during, and after certain extreme weather events. During elevated fire threat and storm conditions, the meteorolgist provides forecasts at least daily. During a PSPS event, which BVES has not yet experienced, BVES's contracted meteorolgist would provide near continuous forecasting. BVES also relies on its Field Operations staff to interpret web-based weather feeds along with the raw data from its weather stations.

This arrangement has proven to be very effective and has become an essential part of BVES's operational planning routine.

Alternatives

The alternative to this approach would be to hire a dedicated meteorologist on staff rather than contract out this service. This alternative was considered as part of the planning though BVES found it to be more cost effective to retain contracted services. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. Variations in localized climates affect the weather coverage across the service territory and the county are not always accurately reflected through RFW and HWW notifications. Additionally, BVES's service area is small (32 square miles). BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. Due to the small size, and local variability not reflected in broader forecasts, BVES believes it is best to apply this initiative to its entire system.

Progress on initiative

In 2021, BVES spent $12,700 (OPEX) on this initiative. This project is an ongoing initiative and relates to activities discussed in **Section 7.3.2.4**.

Variations in localized climates affect the weather coverage across the service territory and the county which are not always accurately reflected through RFW and HWW notifications. Therefore, in addition to deploying an array of 20 weather stations across BVES's 32-square mile service area, BVES has engaged a weather consultant experienced in San Bernardino Mountain weather. BVES's service area is small so the consultant is able to provide a forecast for the service area in a short period of time pointing out exactly which areas are expected to have high wind gusts and sustained winds. BVES utilizes the NFDRS system to assess the dryness and fuel availability that creates dangerous fire conditions. However, during a high fire threat weather event, the consultant will pay particular attention to the "high risk" areas BVES has designated for potential PSPS and the consultant will also focus on the areas where winds (sustained and/or gusts) are particularly high.

Technosylva will initially direct its efforts on building a model to forecast fire threat potential and spread throughout the BVES system. As noted above, BVES's service area and circuits are small in size and there is no efficiency gained by prioritizing one area over another when developing the model. Once the model is developed and implemented, the higher fire threat and spread areas will be prioritized in the monitoring for possible PSPS.

BVES maintains use of its contracted meteorologist and local forecast observations for field planning activities and fire weather watch. As demonstrated by other utilities, BVES finds that real-time access to this data is pertinent to ensuring daily activities are performed under the greatest amount of caution. BVES's entire service area (HFTD Tier 2 and 3) is covered by the initiative.

BVES has a system in place to evaluate high risk fire threat weather through its weather consultant, using the NFDRS, and real-time wind speed (sustained and/or gusts). In 2022, BVES will continue to refine this process and improve the dissemination of fire threat weather to additional staff.

Additionally, BVES is working with Technosylva to implement a more robust fire threat prediction and fire spread model that will provide BVES near real-time assessment of the fire threat along its circuits. The product will superimpose a color coded "heat map" on BVES's circuit maps in a GIS overlay. The heat map will indicate the degree of wildfire risk at any point on BVES's circuits through the gradients of the color coding (red being highest risk and blue being lowest risk) to assist BVES in its PSPS decision making process.

The RSE value for this initiative is 20. Projected spend (OPEX) is $13,000 in 2022, $13,500 in 2023 and $13,900 in 2024. Costs are equally spilt with the forecast in **Section 7.3.2.4**.

Future improvements to initiative

BVES expects to apply the results of the initiative in its wildfire mitigation planning and resource allocation in a future WMP update. BVES will monitor and evaluate the results of the initiative and implement improvements from lessons learned as applicable to ensure a process of continuous improvement is applied to the initiative.

On-demand weather analysis and forecasting capabilities will be further enhanced in 2022 through BVES's engagement with Technosylva. In conjunction with contracted meteorological support, BVES will have optimal situational awareness into potential service area fire risk conditions. As Technosylva's models are further implemented, BVES will re-evaluate the role of its weather consultant and use of NFDRS in its PSPS decision making process. This evaluation will be done in 2023.

7.3.3 Grid Design and System Hardening

This section is revised to address RN-BVES-22-03: BVES has not sufficiently connected its risk assessment with its mitigation initiative prioritization

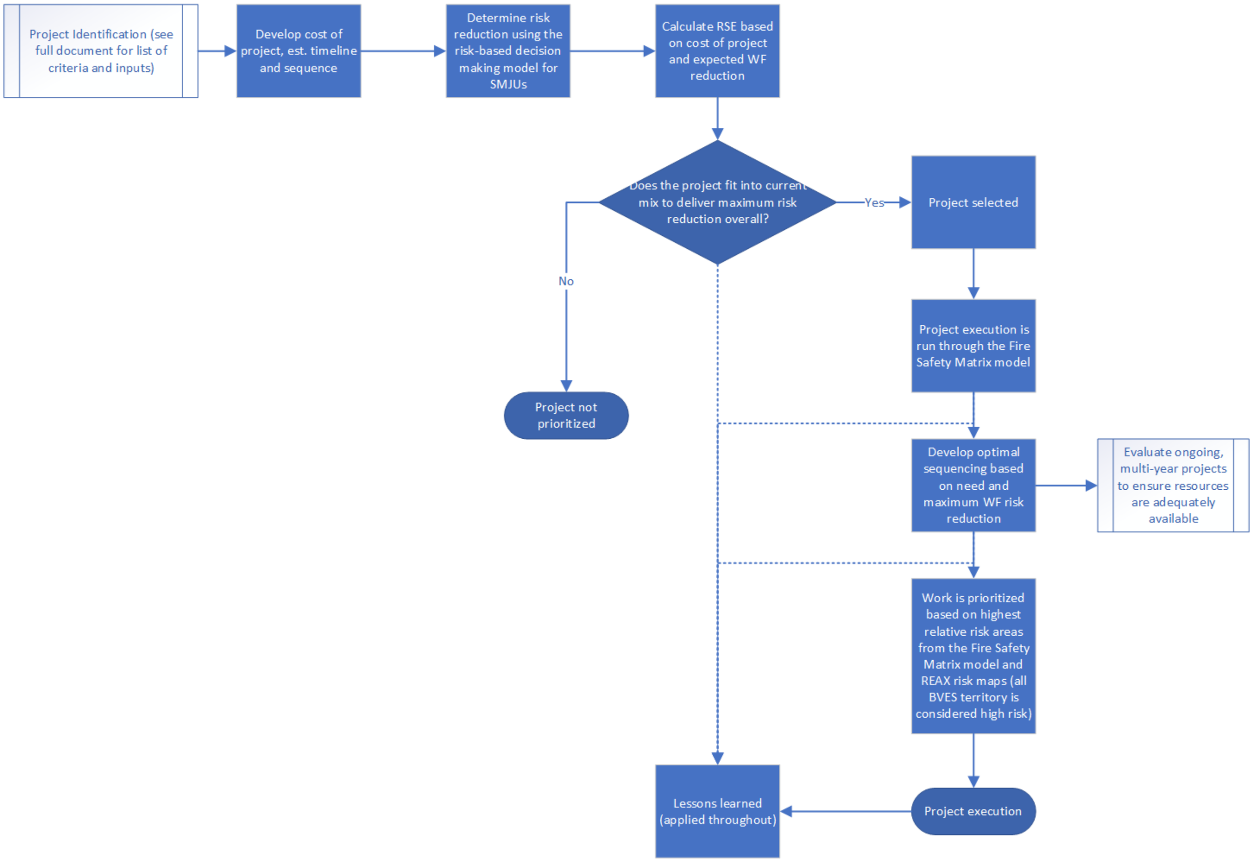
The BVES grid design and system hardening investments will reduce the risk of potential ignition sources. Reducing ignition sources is one of the most critical elements for mitigating wildfire and eliminating the need for PSPS. BVES is making several systems hardening investments, each one specifically designed to reduce ignition sources, while considering the cost and risk reduction effectiveness.

It is BVES's vision to complete all planned system hardening investments, except for the 4kV covered wire program, within the 10-year planning period, while a significant portion of the investments are anticipated to be completed in the next two- to three-year timeframe. The highest risk 4kV areas will be mitigated in the 10-year planning period.

BVES continues to monitor industry practices as it relates to wire down detection programs. BVES currently does not have a wire down detection program, nor does it have a timeline to procure one. As solutions are developed in this space and BVES is able to collaborate with other utilities on the effectiveness (target of greater than 85%) of their programs BVES will invest in such technology.

The flowchart below summarizes how BVES selects projects (detailed discussion provided in **Section 7.2**).

Figure 7.3-4: Project Selection Flowchart



7.3.3.1 Capacitor maintenance and replacement program

This initiative covers the **Capacitor Replacement and Maintenance Projects** including the Capacitor Bank Upgrade Project.

A detailed inspection is performed on the 24 capacitor banks each year beginning in 2022. The inspection for 2022 was completed in July 2022.

Capacitor banks are also inspected at the following times:

- During system detailed inspections every five years per GO 165 system patrol
- Patrol inspections - BVES performs two full patrols of its system per year (exceeding the GO 165 requirement)
- UAV thermography and HD photography/videography (exceeding the GO 165 requirement)
- Anytime a capacitor bank is placed in service or removed from service basic inspection maintenance is performed in accordance with BVES's Capacitor Operation Maintenance Policy and Procedures.

Additionally, BVES plans to replace six capacitor banks per year beginning in 2023. The capacitor banks will be replaced with 450kVAR 3-phase units with remote control and monitoring capability through SCADA. Connectivity to SCADA will be via radio/cellular data transfer equipment and the BVES service area fiber optic network. This will allow BVES to control voltage by placing or removing the capacitor banks from service, as needed, without sending a crew to manually operator the capacitor banks.

Additionally, the capacitor banks will be continuously monitored to prevent overheating or excessive voltage which may lead to catastrophic failure.

In 2023, BVES intends to re replace the following capacitors:

Table 7.3-3: Capacitor Replacement List

Year	Element Name	Type	Phasing	Upline Source	Upline Feeder	Address	Status
2023	C12525BV	Capacitor	ABC	Village	BoulderBreaker	39649 Big Bear Blvd, Big bear Lake, CA 92333	ONLINE
2023	C11207BV	Capacitor	ABC	Village	Boulder Circuit	South of, 40074 Big Bear Blvd, Big Bear Lake, CA 92315	OFFLINE, DAMAGED
2023	C7027BV	Capacitor	ABC	Maltby	ErwinLake Circuit	1048 Willow Ln, Big Bear, CA 92314	ONLINE
2023	C6116BV	Capacitor	ABC	Maltby	ErwinLake Circuit	866 Lakewood Dr, Big Bear, CA 92314	OFFLINE
2023	C3216BV	Capacitor	ABC	Fawnskin	North Shore Circuit	39222 N Shore Dr, Big Bear, CA 92314	ONLINE
2023	C10014BV	Capacitor	ABC	Maltby	Paradise Circuit	116 W Sherwood Blvd, Big Bear, CA 92314	OFFLINE

Risk to be mitigated */ problem to be addressed*

Work performed under this initiative aims to maintain existing equipment, reduce the risk of ignitions due to equipment faults and failures, and deploy new equipment to reduce risk of ignition drivers.

Initiative selection *("why" engage in activity)*

"why" engage in activity
This is part of ongoing electrical maintenance and prevention activities intended to provide a plan for any remediation, adjustments, or installations of new equipment to improve or replace existing capacitors and reduce the likelihood of faults or failures that may result in ignitions.

Alternatives
There are no other considered alternatives to these maintenance activities.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). All of the capacitor bank replacements will take place in the Tier 2 HFTD zone and will be prioritized based on need and relative risk. There are no capacitor banks in the HFTD Tier 3 area.

Progress on initiative

BVES spent $8,774.93 (OPEX) in 2021 covering the regions of Tier 2 and Tier 3.

In the next year, BVES does not have an immediate plan apart from routine preventative maintenance activities. BVES intends to evaluate capacitors in 2022 with a potential CAPEX plan in 2023. Current work reported falls under maintenance activities.

The RSE value for this initiative is 3.81. Projected spend (OPEX) is $9,000 in 2022, $9,300 in 2023, and $9,500 in 2024. CAPEX planning is budgeted for $345,000 in 2023 and $319,100 in 2024.

Future improvements to initiative

BVES plans for potential equipment upgrades in 2023. The project aims to replace 24 capacitor banks from 2023 – 2026. The new capacitor banks will replace significantly aging (>40 years-old) manually operated capacitor banks. The existing capacitor banks are beginning to show signs of possible future failure, which in the worst case could result in explosion of the capacitor and the potential for ignition. The new capacitor banks will be connected to the SCADA system for remote operation, control and monitoring of performance. In addition, the project will study the locations that will result in optimized voltage support and control.

7.3.3.2 Circuit breaker maintenance and installation to de-energize lines upon detecting a fault

This initiative covers the **Circuit Breaker Maintenance and Installation Program**.

Risk to be mitigated */ problem to be addressed*

This activity addresses the remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES routinely maintains these electrical assets to prevent ignition risk and aid in future fault detection deployments.

Circuit breaker inspections at substations are mandated by the CPUC through GO 174 facilities inspections. Circuit breakers are used for high voltage switching and to isolate faults in a timely manner before the faults can cascade into a complete system outage. Circuit breakers in a substation protect the power grid from events such as a surge in voltage due to a lightning strike. Circuit breakers are generally inspected and maintained periodically every four years. Depending on the type of breaker, these inspection and maintenance tests include oil analysis, vacuum/gas checks, speed analysis, or other industry analysis standards.

Alternatives
No comparable alternative exists. Circuit Breaker Inspections are mandated by GO 174. These inspections are completed throughout the BVES service territory. BVES tracks the conditions found during the detailed inspections and evaluates the types and quantity of conditions in order to identify trends and remedial actions.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. All of the circuit breakers to be maintained or installed are in Tier 2 and will be prioritized based on need and relative risk.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative *(amount spent, regions covered) and plans for next year*

In the next year, BVES will conduct circuit breaker maintenance through electrical equipment inspections and has no immediate plans for installing devices to abate PSPS risk impact.

BVES spent $59,187.54 (OPEX) in 2021 covering the regions of Tier 2 and Tier 3. Projected spend (OPEX) is $60,600 in 2022, $62,500 in 2023, and $64,300 in 2024.

The RSE value for this initiative is 9.62.

Future improvements to initiative

BVES exchanges best practices on circuit breaker maintenance with other utilities and will implement changes as applicable. BVES also will explore the latest in circuit breaker maintenance and operations by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest circuit breaker maintenance practices in T&D literature and periodical.

7.3.3.3 Covered conductor installation

Covered conductors are any conductors (wires) covered by layers of insulation. Vendors designed these wires to withstand incidental contact with vegetation or other debris. Bare wires were historically used because they provided a reliable, cost-effective solution for delivering energy to customers. Additionally, many California utilities have historically used bare wires as a best practice for reliability purposes. Based on pilot programs conducted under earlier WMPs that demonstrated reduced fire risk and no impacts on reliability, BVES has decided to replace bare conductors with covered conductors on all sub-transmission lines (34.5 kV) and to replace all bare 4 kV distribution wire in high-risk areas within the service area with covered wire. The replacement program is prioritized based on higher-risk circuits to maximize the risk reduction.

BVES has a **Covered Wire Program** to replace 34.5 kV bare wire at a rate of 4.3 circuit miles per year and to replace 4 kV bare wire at a rate of 8.6 circuit miles per year. Additionally, the **Radford Line Replacement Project** is addressed under this subsection.

Three programs scheduled under this initiative activity are captured in the below sections **7.3.3.3.1**, **7.3.3.3.2**, and **7.3.3.3.3**.

7.3.3.3.1 & 7.3.3.3.2 Covered Wire Program – (4kV & 34.5kV) Systems

Based on the results of the completed covered conductor pilot programs, BVES developed both the 34.5Kv and 4Kv Covered Wire Installation Programs.

Risk to be mitigated */ problem to be addressed*

This initiative intends to reduce potential ignition events by installing wire with insulated protective covers. This initiative addresses the replacement of standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield).

Initiative selection *("why" engage in activity)*

Covered Wire Program – 34.5 kV System

"why" engage in activity

BVES intends to install covered wire on all sub-transmission lines (34.5 kV). This action will result in the entire overhead 34.5 kV system in the HFTD being either underground or covered. This program will reduce the risk of sub-transmission lines contacting vegetation or other debris and causing an ignition to near zero.

BVES plans to replace all overhead sub-transmission bare wire with covered wire over a 6-year period of execution from 2020 to 2026 covering approximately 4.3 miles per year.

Alternatives

Covered wire is an accepted practice to eliminate tree and vegetation and debris contact to reduce wildfire ignitions. Undergrounding the 34 kV system would be the only other technically acceptable alternative. However, the cost would be over 10 times that of the covered wire replacement project. Additionally, certain areas would be significantly challenging to underground the overhead system. The covered wire program yields a more attractive RSE.

Covered Wire Program – 4 kV System

"why" engage in activity

BVES intends to replace all bare 4 kV distribution wire in identified high-risk areas within the HFTD with covered wire. This action will result in approximately 86 miles of the 4 kV distribution lines in the system in the HFTD being covered at approximately 8.6 miles per year for the next 10 years. Based upon this schedule, 4kV wire in high-risk areas will be replaced by 2032. The remaining 4 kV lines will take another 10 years. This program will significantly reduce the risk of distribution lines contacting vegetation or other debris and causing an ignition. The high-risk areas are primarily defined by high vegetation density.

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor suppliers, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%. For comparison, the SCE estimated full deployment of covered conductor in high-risk areas to mitigate approximately 60 percent of fires associated with electrical distribution facilities in defined risk tiers.[49] BVES believes SCE's effectiveness results are a valid, relative measure of effectiveness of this technology, with underground conversion providing the baseline (100 percent) for purposes of our comparison.

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[49] SCE application for approval of its Grid Safety and Resiliency Program, U 338-E, September 10, 2018

Alternatives

BVES compared undergrounding versus covered conductors. Undergrounding the 34 kV system would be the only other technically acceptable alternative. However, the cost would be 10 times that of the covered wire replacement project. Additionally, certain areas would be significantly challenging to underground the overhead system. The covered wire program yields a more attractive RSE.

Region prioritization *("where" to engage activity)*

Figure 7.3-5: 2022 Planned Covered Conductor Installation Location

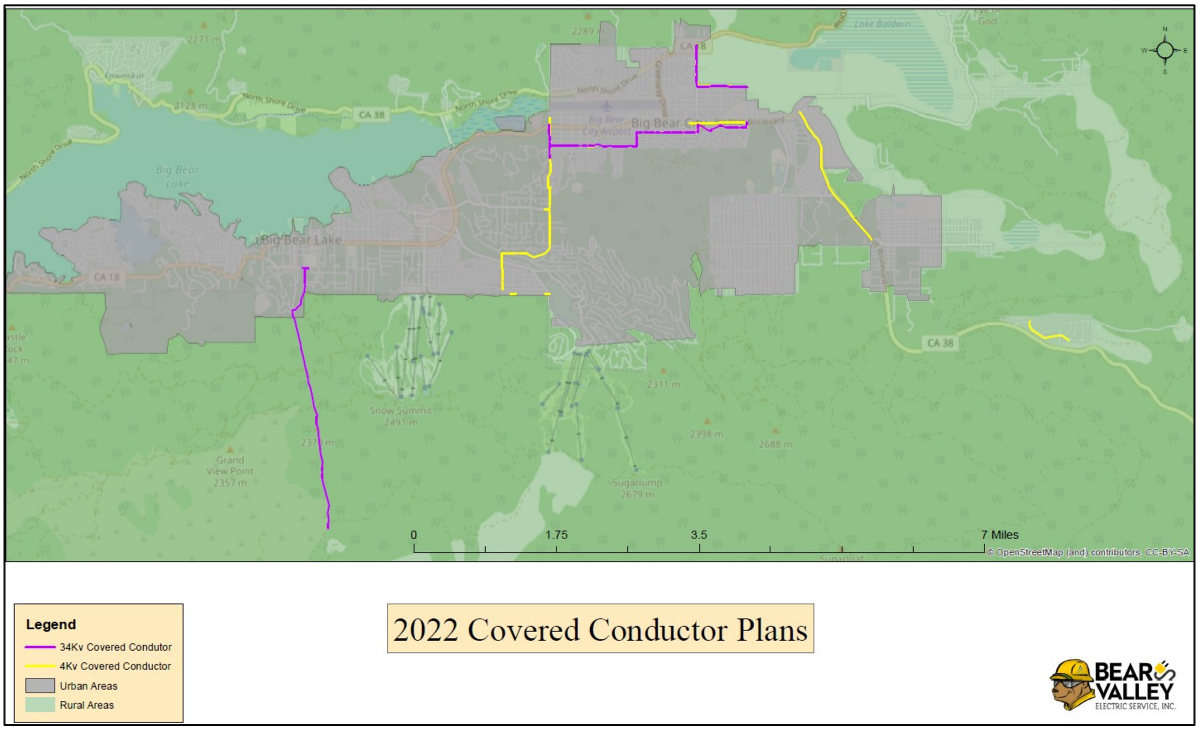
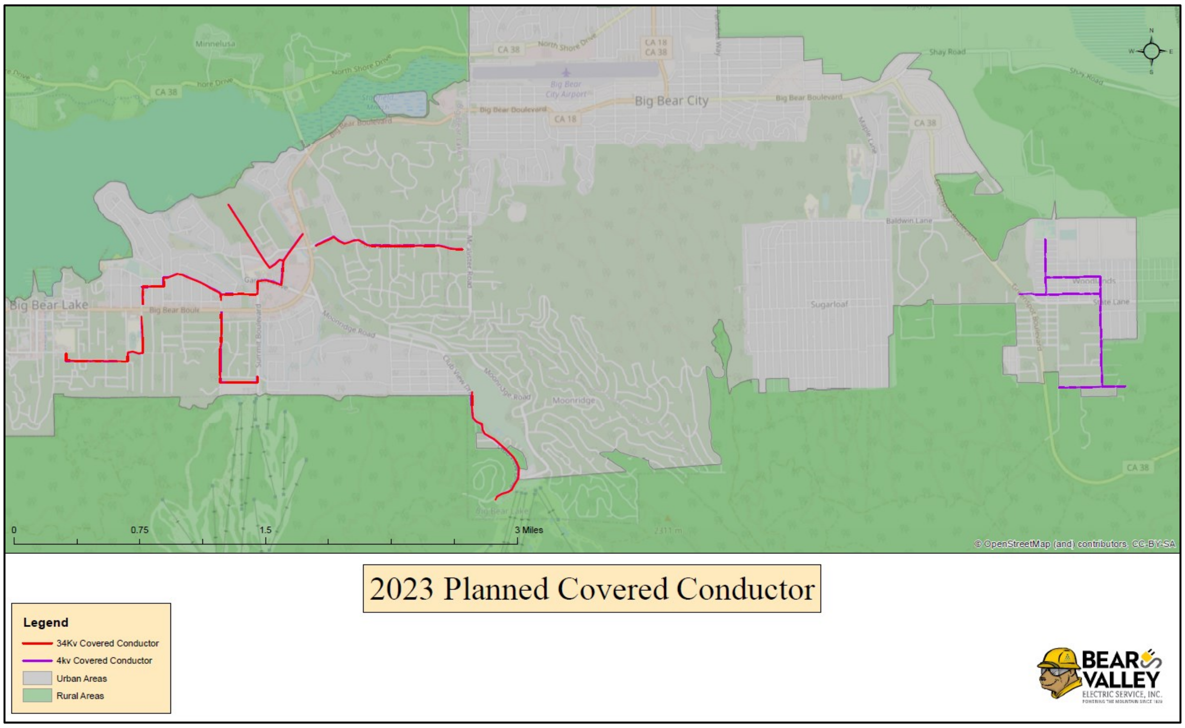


Figure 7.3-6: 2023 Planned Covered Conductor Installation Location



Based on the results of the covered conductor pilot programs, BVES developed both the 34.5Kv and 4Kv Covered Wire Programs. BVES service area is all in Tier 2 and Tier 3 high risk wildfire service areas. Therefore, the grid design and system hardening initiatives are all located in Tier 2 and 3.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

34.5kV System

BVES will continue on high-risk areas towards a program goal of 100 percent completion by end of calendar year 2026. All bare wire in The HFTD Tier 3 is to be covered by end of calendar year 2022 if permitting issues with the USFS are resolved in time to complete construction prior to the winter of 2022.

4kV System

BVES will continue replacing 4 kV bare wire in high-risk areas towards a program goal of 100 percent completion (for high-risk areas) by end of calendar year 2032. BVES will then continue to replace 4 kV bare wire until it no longer has bare wire in its 4kV system.

BVES spent $6,156,716.00 (CAPEX) in 2021 covering 12.3 miles of bare wire within Tier 2. BVES has budgeted for 12.90 of circuit miles treated each year approximating (CAPEX) $6,570,400 in 2022, $6,836,700 in 2023, and $6,767,600 in 2024.

The RSE value for this initiative is 0.21.

Future improvements to initiative

BVES will apply any lessons learned throughout the progression of the program. BVES collects information on supply logistics, pole replacements necessary to support covered wire installation, and covered wire installation work techniques and rates in order to optimize the program execution.

BVES participates in the joint utilities workshop on covered wire and will continue to exchange information in this area with other utilities. BVES will attend T&D conferences and review T&D literature and periodicals on the latest in covered wire operations and maintenance.

7.3.3.3.3 Covered Conductor Project – Radford Line Sub-transmission Project

This project includes two components: (1) replacement of the bare wire with covered conductor and (2) replacement of the wood poles with fire resistant poles. The bare wire replacement portion of the project is discussed and tracked in this initiative. The pole replacement portion of the project is discussed and tracked under initiative **Section 7.3.3.6** (Distribution pole replacement and reinforcement, including with composite poles).

***Risk to be mitigated** / problem to be addressed*

This initiative intends to reduce potential ignition events by installing wire enclosed with protective shielding by the manufacturer and improve resiliency of the system by replacing the aged wood poles with fire resistant poles. This includes installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield).

***Initiative selection** ("why" engage in activity)*

"why" engage in activity

BVES is replacing bare wire with covered conductor on the Radford 34.5 kV line. BVES chose to cover this line specifically, which resides in the HFTD Tier 3 area, since it has the highest wildfire risk of all of BVES's overhead facilities. The line is in a densely vegetated area that is difficult to patrol, due to no road access. The project also includes replacing the aged wood poles with fire resistant poles. Replacing the bare wire with covered wire will provide a high level of effectiveness for preventing a potential ignition leading to a wildfire. Utilizing fire resistant poles will improve resiliency to quickly restore power to Big Bear Lake in the event the area suffers a major wildfire.

Alternatives

The USFS requested BVES consider undergrounding the Radford Line as an alternative. BVES undertook this analysis and concluded that it was not practical to underground this line due to the steep slopes, significant disturbance to the environment during construction, and significant degradation in BVES's ability to perform preventative maintenance, inspections, equipment upgrades, troubleshooting faults, and corrective maintenance.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Based on the results of the covered conductor pilot programs, BVES plans to harden the Radford line in Tier 3.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

In 2021, for this portion of the project, BVES spent $39,480 on the project on design and plans, environmental assessments, and permitting efforts with USFS.

Once BVES receives approval of its permit request to the USFS to perform the project, BVES will execute the project. BVES must receive approval from the USFS sufficient time in the seasonal construction period to complete the project or it will be deferred to late in 2022. The construction period ends October 31st of each year.

The project construction period is estimated at three months. BVES budgeted (CAPEX) $1,236,000 in 2022 for the covered wire portion of the project.

The RSE value for this initiative is 0.19.

Future improvements to initiative

BVES will apply any lessons learned throughout the progression of the program. As part of the project BVES will install utility fiber cable and will use this for future system monitoring efforts (cameras, infrared sensors, system diagnostics sensors, etc.) and for fast acting switches on the circuit.

BVES participates in the joint utilities workshop on covered wire and will continue to exchange information in this area with other utilities. BVES will attend T&D conferences and review T&D literature and periodicals on the latest in covered wire operations and maintenance.

7.3.3.4 Covered conductor maintenance

This initiative covers all **Covered Conductor Maintenance**.

Risk to be mitigated */ problem to be addressed*

BVES will maintain the installed covered conductor in accordance with prescribed maintenance standards and industry best practices. This will include remediation and adjustments to installed covered or insulated conductors. This will reduce the chance of degradation to the covered wire and potential for ignition sources to develop.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES will maintain these hardened conductors as described and has established a separate initiative for maintenance activities. Covered conductors are inspected as follows:

- Detailed asset inspections
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

Covered conductor issues identified in the inspections are documented and corrected in accordance with GO 95 Rule 18 prioritization.

Alternatives

There are no alternatives to maintaining the covered conductor installation.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES targeted Tier 2 and Tier 3 for the covered conductor deployments, targeting highest risk circuits.

Progress on initiative

The RSE value for this initiative is 19.36. BVES spent $29,396.36 (OPEX) in 2021. BVES budgets (OPEX) $30,100 in 2022, $30,100 in 2023, and $32,000 in 2024.

Future improvements to initiative

Now that covered wire is in the system and its use is increasing, BVES will be allocating maintenance resources to properly maintain the covered wire according to standards. BVES will apply any lessons learned throughout the progression of the program.

BVES participates in the joint utilities workshop on covered wire and will continue to exchange information in this area with other utilities. BVES will attend T&D conferences and review T&D literature and periodicals on the latest in covered wire operations and maintenance.

7.3.3.5 Crossarm maintenance, repair, and replacement

This initiative covers all **Crossarm Maintenance Activities.**

Risk to be mitigated */ problem to be addressed*

This initiative includes remediation, adjustments, or installations of new equipment related to crossarms in accordance with GO 95. Maintaining and replacing these support structures will reduce the risk of equipment failure and subsequent ignition risk.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES maintains its electrical system in accordance with applicable GOs and industry standards. Costs for new crossarms installed during pole replacements are captured in CAPEX for that specific pole replacement project while repairs and general maintenance is captured as O&M costs. Crossarms are inspected as follows:

- Detailed asset inspections
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

Crossarm issues identified in the inspections are documented and corrected in accordance with GO 95 Rule 18 prioritization.

Alternatives
There are no alternatives to maintaining BVES's electrical system to report.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. Therefore, the highest risk circuits will be prioritized but will align with pole inspection and replacement schedules.

Progress on initiative

BVES has begun utilizing composite cross arms as an improved material in terms of strength, durability, and less susceptible to fire damage, in its construction and replacement practices and will continue to make further improvements.

BVES spent $51,443.64 in 2021 on repair and maintenance activities within Tier 2 and Tier 3 regions of the service territory. Projected spend (OPEX) for this initiative is $52,700 in 2022, $54,300 in 2023, and $56,000 in 2024.

The RSE value for this initiative is 11.06.

Future improvements to initiative

BVES exchanges best practices on crossarm maintenance with other utilities and will implement changes as applicable. BVES also will explore the latest in crossarm maintenance and operations by attending T&D conferences and meeting with other utilities and vendors. BVES will apply any lessons learned throughout the progression of the maintenance and replacement program to improve its wildfire mitigation efforts.

7.3.3.6 Distribution pole replacement and reinforcement, including with composite poles

This initiative covers costs associated with four separate programs and projects, which includes **Distribution Pole Replacement and Reinforcement – GO 95 Projects** (**7.3.3.6.1**) the **Covered Conductor -Radford Line Project** (also associated with **Section 7.3.3.3.3**) (**7.3.3.6.2**), the **Evacuation Route Hardening Program / (Pilot)** (**7.3.3.6.3**).

7.3.3.6.1 Distribution Pole Replacement and Reinforcement – GO 95 Projects

***Risk to be mitigated** / problem to be addressed*

In compliance with GOs 95 and 165, BVES has an ongoing program to assess and remediate noncompliant distribution poles. Noncompliant poles are a fire risk. Since the entire BVES service area is in a HFTD Tiers 2 and 3, any pole failure is considered a high fire risk. Additionally, BVES is above 3000 ft sea level and is subject to heavy loading requirements. Overhead distribution lines are exposed to severe weather including heavy snow, ice, and high winds.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
GO 95 Rule 43.1 requires BVES to design, build, and maintain their overhead facilities to withstand foreseeable fire and wind conditions in the service territory. Poles that are not compliant with GO 95

safety factors will be identified, and the appropriate remediation will be designed and implemented. Meeting or exceeding the mandates of GO 95 is critical to mitigate wildfires. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability.

Alternatives

There are no reasonable alternative approaches to reducing wildfire risk due to non-compliant poles other than adequately testing all poles and taking remedial action, where required. There are alternatives as to the rate in which pole testing is conducted. To promote efficiency and minimize duplication of work, and subject to the remediation time frames in GO 95, the rate of testing and resulting remediation designs may be integrated with other potential work proposed in the same area which is also more operationally efficient and cost effective. In addition, the program may require a sufficient number of pole replacements on a line or in a concentrated area that it is prudent to undertake a more comprehensive replacement design, as opposed to mere replacement of individual poles. The remediation work is performed by BVES or contractor resources based on available capacity, cost, and other related factors.

Region prioritization *("where" to engage activity)*

BVES's entire service area is in Tier 2 and Tier 3 high risk wildfire service areas. Therefore, BVES follows an inspection and maintenance schedule to target priority pole replacements and remediation actions. BVES is proactively performing pole loading test beyond the GO 95 / 165 requirements, including the heavy loading requirements. The pole loading program is combined with the covered conductor program, outlined in section 7.3.2.2.2, which is prioritized to address the highest risk areas of the service territory.

Progress on initiative

The RSE value for this initiative is 2.86. In 2021, BVES spent $569,410 (CAPEX) on various small scale pole replacement projects to bring failed poles into compliance with GO 95 in the service territory within Tier 2 and Tier 3 HFTDs. This included replacing 216 poles based on fire resilience efforts and failed assessments.

BVES's estimated budget for 2022 (CAPEX) is $400,000, $832,400 in 2023, and $824,000 in 2024.

Future improvements to initiative

Where possible, BVES looks for synergies between initiatives such as the "covered wire installation" and "pole loading infrastructure hardening and replacement program based on pole loading assessment program" to achieve the objectives of this initiative. BVES will apply any lessons learned throughout the progression of the program.

BVES participates in the joint utilities covered wire working group and will continue to exchange information in pole replacements associated with covered wire installation. Additionally, BVES will participate in T&D conferences and review current T&D literature and periodicals to gain the latest information on pole replacement practices.

7.3.3.6.2 Covered Conductor Project – Radford Line Sub-transmission Project

Risk to be mitigated */ problem to be addressed*

This initiative intends to reduce the potential of one of the main power supply lines to Big Bear Lake from being lost, should the area suffer a wildfire or other event. Additionally, the initiative removes the likelihood BVES would need to initiate a PSPS on this circuit during extreme fire weather conditions.

Initiative selection ("why" engage in activity)

"why" engage in activity

As discussed in **7.3.3.3** above, BVES is replacing 70 aged wood poles on the Radford 34.5 kV line with fire resistant poles that will improve resiliency to quickly restore power to Big Bear Lake in the event the area suffers a major wildfire.

BVES chose to cover this line located in the HFTD Tier 3 area and replace the poles with fire resistant poles specifically because it has the highest wildfire risk of all of BVES's overhead facilities. The line is in a densely vegetated area that is difficult to patrol, due to no road access. Replacing the poles will improve system resiliency from wildfires and reduce the likelihood that BVES would need to declare a PSPS on this line.

Alternatives
The USFS requested BVES consider undergrounding the Radford Line as an alternative. BVES undertook this analysis and concluded that it was not practical to underground this line due to the steep slopes, significant disturbance to the environment during construction, and significant degradation in BVES's ability to perform preventative maintenance, inspections, equipment upgrades, troubleshooting faults, and corrective maintenance.

Region prioritization ("where" to engage activity)

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

The Radford Project is mostly in the HFTD Tier 3 and partially in the HFTD Tier 2. Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

The RSE value for this initiative is 0.19. In 2021 for this portion of the project (pole replacement), BVES spent $39,480 on the project on design and plans, environmental assessments, and permitting efforts with USFS.

Once BVES receives approval of its permit request to the USFS to perform the project, BVES will execute the project. BVES must receive approval from the USFS sufficient time in the seasonal construction period to complete the project or it will be deferred to 2023. The construction period ends October 31st of each year. The project construction period is estimated at three months. The total project cost for this portion is estimated to be $4,382,100.

Future improvements to initiative

BVES will apply any lessons learned throughout the progression of the program. As part of the project BVES will install utility fiber cable and will use this for future system monitoring efforts (cameras, infrared sensors, system diagnostics sensors, etc.) and for fast acting switches on the circuit.

BVES participates in the joint utilities covered wire working group and will continue to exchange information in pole replacements associated with covered wire installation. Additionally, BVES will participate in T&D conferences and review current T&D literature and periodicals to gain the latest information on pole replacement practices.

7.3.3.6.3 Evacuation Route Hardening Pilot & Program

***Risk to be mitigated** / problem to be addressed*

The primary objective of this pilot demonstration and subsequent program is to develop tools an approach to add resiliency and safety during an evacuation due to a wildfire.

***Initiative selection** ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives*

"why" engage in activity
BVES's service area has three predetermined evacuation routes, developed by the local sheriff department and other government officials, to evacuate the public in the event of an emergency, including a wildfire. The hardening of BVES electrical assets (poles, wires, equipment) along the evacuation routes is important to ensure they do not fail during a wildfire, which would limit mobility along the evacuation routes required to safely perform the evacuation.

The evacuation hardening pilot project performed in 2020 and completed in 2021 was designed to determine availability, cost effectiveness, and ability to install technology such as fire-resistant pole wrap, steel poles, concrete poles, ductile iron poles, and fire-resistant fiberglass poles. These proposed measures are intended to increase resiliency to demonstrate the ability to keep evaluation routes safe from failed BVES electrical assets during a wildfire.

Pilot Results: The pilot program consisted of using BVES's previous experience with other projects, testing new technologies, collaborating with other utilities, and performing industry literature research on the matter. BVES tested two technologies -- fire resistant pole wire mesh wrap and fire-resistant fiberglass poles. For technologies that BVES does not test directly, such as concrete poles, BVES staff will work with other utilities to gain from their experience. Some of the pilot program results to date are:

1. BVES successfully installed wire wrap mesh on three poles. This system is being used by other utilities and test information from the manufacturer indicates it is a reliable, cost-effective solution. The all-in cost per pole for the wire wrap mesh is approximately $1,550 per pole or approximately $59,000 per circuit mile.
2. BVES has significant recent experience undergrounding overhead facilities. While this is very effective for the stated goal, it is also very expensive running at approximately $4,000,000 per circuit mile.
3. BVES has recent experience installing fire resistant composite poles. While this is also effective for the stated goal, it is more expensive than the wire wrap mesh at approximately $17,320 per pole or $640,000 per circuit mile.

BVES tested light weight steel (LWS) poles in the first half of 2021 as part of its pilot program, completing the schedule for this initiative. While based on other utility experience and industry literature, this is effective for the stated goal, it is more expensive than the wire wrap mesh running at approximately $15,900 per pole or $587,000 per circuit mile. BVES will also assess ductile iron poles for use on evacuation routes as part of its Radford Line Replacement Project. Once again, while based on other utility experience and industry literature, this is effective for the stated goal, it is more expensive than the wire wrap mesh running at approximately $15,720 per pole or $581,000 per circuit mile.

Implementation of an Evacuation Route Hardening Program
Hardening of BVES electrical assets (poles, wires, equipment) along the evacuation routes is important to ensure they do not fail during a wildfire which would limit mobility along the evacuation routes required to safely perform the evacuation. The primary objective of this evacuation route hardening program is not to reduce the risk of ignition resulting in a wildfire. Rather, the primary objective of the program is to add resiliency and safety to evacuation routes during an evacuation due to a wildfire or other emergencies.

BVES intends to harden the three main evacuation routes (800 poles) over two years with wire wrap program. In addition, BVES will implement the following policy that requires when wood poles are to be replaced for any reason on main evacuation routes, that they are to be replaced with fire resistant composite or other acceptable pole types (LWS or ductile iron after testing). If undergrounding opportunities arise along evacuation routes, evaluations will be performed to determine the suitability of undergrounding.

Following hardening of main evacuation routes, BVES plans to continue to install wire wrap on wood poles in selected high-risk areas. This long-term plan is expected to cost approximately $800,000 per year for six to eight years.

Alternatives
There is no alternative to hardening evacuation routes, but there are alternatives as to how the evacuation routes are hardened. This pilot is designed to explore various options such as fire-resistant pole wrap, steel poles, and concert poles to provide more information for BVES decision-making.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES’s service area is small (32 square miles). Additionally, BVES’s HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. There are no roadways in the HFTD Tier 3; therefore, there are no evacuation routes to be hardened in the HFTD Tier 3.

Project work is selected and sequenced per the process identified in **Section 7.1** “WMP Project Selection and Prioritization Process” and the work process flowchart in **Section 7.3**. This process includes working with local government and agencies responsible for evacuation planning.

Progress on initiative

The RSE value for this initiative is 0.39. In 2021, BVES spent (CAPEX) $16,080 on the pilot project. BVES plans to continue with installing wire wrap mesh on approximately 412 poles in 2022 with a projected spend of (CAPEX) $576,800 in 2022, $816,200 in 2023, and $808,000 in 2024.

Future improvements to initiative

Based on the analysis of the pilot, it is planned that the evacuation route hardening of primary evacuation routes will be completed by the end of calendar year 2022. BVES will apply any lessons learned throughout the progression of the program. BVES will then focus on hardening approximately 500 poles per year from 2023 to 2030.

BVES exchanges best practices on evacuation route hardening with other utilities and implements changes as applicable. BVES will also explore the latest evacuation route hardening practices by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest evacuation route hardening practices in T&D literature and periodical.

7.3.3.7 Expulsion fuse replacement

This initiative covers the **Fuse Replacement Program**.

Risk to be mitigated */ problem to be addressed*

Fuses are devices that protect the distribution system from faulted or damaged lines and equipment. BVES has historically used conventional “expulsive” fuses to protect lines. Conventional fuses expel hot particles and gases when operated, which can start wildfires. Following SB 901 and the increased availability of alternative fusing, utilities are replacing conventional fuses with current limiting fuses (non-expulsion, ELF) on branch line fusing opportunities system-wide.[50]

Accordingly, from 2019-2021 BVES replaced all of its conventional fuses, installing electronic programmable fuses (vacuum style) system-wide such as the S&C TripSaver II. BVES also installed current limiting fuses and electronic fuses that expel no materials, limit the available fault current, and may even reduce the duration of faults. By replacing every fuse with the potential to spark and impact dry vegetation, BVES’s replacement with non-expulsion fuses reduces the risk of a fusing operation to near zero.

Initiative selection *("why" engage in activity)*

"why" engage in activity
From 2015 through 2019, BVES had 84 conventional fuses operate. In 2020, there were a total of 23 fuse events. However, due to the effectiveness of this project only four were conventional fuse events (the others were 16 ELF and 3 TripSavers fuse events). In 2021, there were three events, one in January and two in February. See the graph in **Figure 4.1-2**, which accounts for blown fuse events and the replacement program schedule. Until recently, BVES had approximately 3,114 conventional fuses, all in high-risk wildfire areas. As part of this initiative, BVES replaced approximately 536 conventional fuses with electronic fuses and approximately 2,578 conventional fuses with ELFs. As of December 31, 2021, BVES had replaced all of its conventional fuses. This program will shift in 2022 to normal business operations of maintenance and operations (replace blown ELF with new ELF and maintain Fuse TripSavers per manufacturer’s recommendations).

Alternatives
Three options (described below) were originally considered and evaluated. Option 3, to replace all conventional fuses, was chosen and implemented due to the combination of cost effectiveness and the ability to mitigate ignitions.

Option 1- Leave existing conventional fuses in place. Fuses operate due to a fault on the system. Reducing faults that occur due to lightning strikes, vegetation contacts, equipment failures, and vehicles hitting poles, will reduce the number of conventional fuse operations. Unfortunately, many faults are beyond BVES’s ability to reduce. Leaving conventional fuses permanently in place was determined to constitute an unacceptable ignition risk.

Option 2- Develop a stand-alone program. An independent conventional fuse replacement program that did not consider other work being performed on the pole. This could execute the fuse replacements program faster, but at a significantly higher cost since BVES may be visiting the same pole more than one time to perform work.

[50] The ELF fuse is made by Eaton Cooper Power. It is designed to help protect electric infrastructure.

Option 3- Combined fuse replacements with other work. When other work, such as a pole replacement, is scheduled to be performed on a pole that has a conventional fuse, the fuse is replaced at the same time as the other work. This results in significant labor savings by reducing truck rolls by combining the other work with the fuse replacement program.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES was able to prioritize the HFTD Tier 3 and extended the effort to cover all of the HFTD Tier 2 areas. BVES followed a replacement schedule aligned with other work such as pole remediation and replacements.

Progress on initiative

The RSE value for this initiative is 0.29. BVES spent $1,486,592.97 (CAPEX) in 2021 replacing the remaining 862 conventional fuses across Tier 2 and 3. There are no conventional fuses remaining in the BVES system and the project is now complete. No further spend is expected.

Future improvements to initiative

BVES will apply any lessons learned throughout the progression of the program. Additionally, BVES intends to utilize the programmable features of the electronic programmable fuses once its SCADA network is fully established in its service area. This will allow BVES to optimize fuse settings remotely and rapidly for various weather and operating conditions.

7.3.3.8 Grid topology improvements to mitigate or reduce PSPS events

This initiative covers the **Switch and Field Device Automation Project**.

Risk to be mitigated */ problem to be addressed*

This plan supports actions taken to reduce or mitigate potential PSPS activation as well as actions to limit the scope and scale of impact to affected community members.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Sectionalizing electrical equipment enables the utility to narrow the scope of affected circuits and equipment in the event of a PSPS activation. BVES has completed prior assessments of device needs and concluded this activity in 2019. In 2023, BVES will implement a new project to install additional switching devices for supply transfer ability to mitigate load loss or PSPS event impact.

Alternatives
Alternatives to suitable switching equipment include the ability to island equipment and sections of the grid with microgrids or local generation. BVES manages an 8.4 MW power plant that can support base customer load in the event of PSPS activation with plans to install a battery and solar solution, which has been delayed for siting issues until 2023.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Therefore, BVES will prioritize projects that target highest risk circuits.

Progress on initiative

BVES had no recorded spend or activities in 2021.

BVES completed this initiative in 2019. From 2023 – 2026, BVES will implement the Switch and Field Device Automation Project, which aims to connect and automate 28 34 kV and 20 4kV switches to the SCADA network over the four-year period.

The RSE value for this initiative is 1.6. BVES has no projected spend in 2022 and anticipates a budget (CAPEX) of $711,050 in 2023 and $673,600 in 2024.

Future improvements to initiative

BVES will continue to routinely determine any future needs for additional sectionalization equipment and apply any lessons learned in the event of a PSPS activation. BVES will commence the Switch and Field Device Automation Project in 2023.

7.3.3.9 Installation of system automation equipment

This initiative covers the **Grid Automation Program // SCADA** (**7.3.3.9.1**), **the Fault Isolation Localization and Service Restoration (FLISR) Program** (**7.3.3.9.2**), the **Fuse TripSaver Automation Program** (**7.3.3.9.3**), the **Server Upgrade Project** (**7.3.3.9.4**), and the **Distribution Management Center Program** (**7.3.3.9.5**).

7.3.3.9.1 Grid Automation Program (SCADA)

Risk to be mitigated */ problem to be addressed*

This initiative is aimed at reducing the risk of ignitions due to faults by enhancing situational awareness and control of the electric distribution system, rapidly detecting fault conditions, localizing faults, and isolating faults from the system. With the implementation of the SCADA network as part of the Grid Automation Program, BVES will enhance its grid as well as conditional awareness into asset performance and potential incidents. This will provide the utility rapid results, instantaneous reads and communications from system enhancements, and optimize system maintenance and remediation deployments with more precision in system management.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES current SCADA system is inadequate with few controls for the distribution system and limited monitoring capability. Through the Grid Automation Project, BVES will establish a service area network, build out its SCADA software and historian capabilities, connect substations and field switches, and install circuit metering and monitoring devices such as weather stations. This initiative will also include installation of electric equipment to increase the ability to automate the system with operational controls and monitoring. To further enhance its situational monitoring, BVES outlined a number of initiatives that contribute to its information base and facilitate sharing. These initiative resources include web-based

weather resources, BVES-owned weather stations, weather forecasting, and GIS-supported applications, such as its Outage Management System (OMS).

BVES plans to continue to automate its system including the installation of a fiber optic network throughout the service area, automating substations and key field switches, and adding sensors to provide critical system information. Grid automation will enhance operational efficiency, safety, reliability, and wildfire prevention by allowing remote monitoring and real-time fault detection. The fiber optic network is also an enabler for future advanced technologies that reduce wildfire ignition risk.

BVES will continue to monitor pilot programs and innovations of the three large investor-owned utilities in California as well as other utilities in the electric transmission and distribution sector. As these California utilities and other utilities progress with wildfire hardening measures and strategies, BVES will evaluate the applicability and efficacy to its service area and specific wildfire risks. As BVES continues to monitor the progress of these technologies, pilots or installations may be conducted over the next three-year period.

Alternatives

For the most part, there are no reasonable alternatives to SCADA systems. Nearly all utilities have SCADA systems for advance monitoring and control. Alternative discussions were considered as part of the planning before this initiative began. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

The SCADA project will serve the entire BVES service area since ethe marginal cost of performing this work on a smaller area is insignificant compared to including the entire service area.

Progress on initiative

The following list demonstrates the current assets monitored and/or controlled via BVES's SCADA system.

Asset
All Bear Valley Power Plant (BVPP) Controls
7.4 kV7 4 kV Circuit Breakers for each of the BVPP generators at the BVPP
4 - 34 kV Ring Bus Circuit Breakers (# 22, 44, 66 & 88) at Meadow Substation
9 Fault Localization Isolation System Restoration 34 kV IntelliRupter Switches (Baldwin IR3430, Shay IR3440, PS3435IR, PS3454IR, PS3436IR, PS3428IR, PS3414IR, PS3415IR & PS3456IR)
Shay 34 kV Auto Recloser (IR3440)
Baldwin 34 kV Auto Recloser (IR3430)
Radford 34 kV Auto Recloser (IR3470)
Palomino Substation

In 2022, BVES plans to connect two substations to the SCADA network. In 2023-2024, the Substation Automation Project will be implemented, which will connect three substations per year to the SCADA network. The following items will also be connected in 2023.

Asset

6 Capacitor Banks – 6 locations: 2 on the Boulder Circuit, 2 on the Erwin Circuit, 1 on the North Shore Circuit and 1 on the Paradise Circuit
8 - 34 kV Field Switches
4 - 4kV Field Switches at 4 tie switch locations
Trip Savers at 4 locations (Radio Study)
Fault Indicators (FI) – proposed to install 79 FI's, Radio Study will be part of the trip saver radio study. (7 locations on 34kV for SCADA connection) All Bear Valley Power Plant (BVPP) Controls

BVES spent $3,129,950 (CAPEX) in 2021 supporting the Grid Automation Program in Tier 2 and Tier 3 HFTDs. The work in 2021 resulted in completion of the fiber network throughout the BVES service area utilizing fiber optic cables and radio data transmitters.

BVES projects spending (CAPEX) $210,000 in 2022, $654,100 in 2023, and $655,900 in 2024 in grid automation initiatives.

The RSE value for this initiative is 2.02.

Future improvements to initiative

BVES will leverage the network connectivity capabilities gained by the project to eventually deploy an array of field devices that enhance situational awareness and detect and remedy system faults and potential ignition events. BVES will apply any lessons learned throughout the progression of the program.

7.3.3.9.2 Fault Isolation Localization and Service Restoration (FLISR)

***Risk to be mitigated** / problem to be addressed*

This initiative is aimed at reducing the risk of ignitions due to faults by enhancing situational awareness of the electric distribution system, rapidly detecting fault conditions, and localizing and isolating faults from the system.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
The Fault Localization Isolation and System Restoration (FLISR) installs nine smart high voltage switches and integrates three existing auto-reclosers and one auto-transfer switch on the 34.5 kV system. The system leverages the network installed by the Grid Automation Project to rapidly detect and isolate faults and restore unaffected portions of the system to the maximum extent possible utilizing unaffected power sources and circuit routes. Additionally, the system provides improved information on where to dispatch line crews responding to fault and outage conditions; thereby, reducing the time to detect and remedy potentially dangerous conditions. This program would also allow for additional sectionalization to minimize the impact of PSPS events.

Alternatives
There is no reasonable alternative to installing a FLISR system.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Therefore, BVES would select a project that targets the highest risk circuits.

Project work is selected and sequence per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES spent $189,510 (CAPEX) in 2021 supporting the FLISR Project in Tier 2 and Tier 3 HFTDs. BVES aims to have the project completed and in operation by the end of 2022. Projected spend (CAPEX) in 2022 is $123,600. There are no cost projections in 2023 or 2024.

The RSE value for this initiative is 1.55.

Future improvements to initiative

BVES will look to expanding FLISR capability into the 4 kV distribution system where it is possible due to circuit configurations. BVES will apply any lessons learned throughout the progression of the program.

BVES exchanges best practices on SCADA control and FLISR with other utilities and will implement changes as applicable. BVES will also explore the latest in SCADA control and FLISR practices by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest SCADA control and FLISR practices in T&D literature and periodicals.

7.3.3.9.3 Fuse TripSaver Automation

***Risk to be mitigated** / problem to be addressed*

This initiative is aimed at reducing the risk of ignitions due to conventional fuses (as discussed in Sec. 7.3.3.7 above) and also to increase situational awareness of the electric distribution system, rapidly detecting fault conditions, and restoring the fuses remotely through the SCADA system.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
The Fuse TripSaver Automation is scheduled to connect and automate 160 Fuse TripSavers to the SCADA network over a four-year period. BVES finished replacing all conventional fuses to current limiting and electronic fuses in 2021. In other to fully optimize surveillance of the system, BVES plans to automate the fuses by integrating the devices with the SCADA network.

Alternatives
There is no reasonable alternative to automating and syncing TripSaver fuses to the SCADA network.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Therefore, BVES would select a project that targets the highest risk circuits.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES did not record any spending in 2021 to support this initiative. The project is planned for 2023 and will be completed in 2026. Projected spend (CAPEX) in 2023 is $197,600 and $136,900 in 2024.

The RSE value for this initiative is 7.15.

Future improvements to initiative

No additional improvements are reflected in the planning stages of this initiative. BVES will apply any lessons learned throughout the progression of the program.

BVES exchanges best practices on SCADA control with other utilities and will implement changes as applicable. BVES will also explore the latest in SCADA control practices by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest SCADA control practices in T&D literature and periodicals.

7.3.3.9.4 Server Upgrade Project

***Risk to be mitigated** / problem to be addressed*

This initiative supports the SCADA network configuration by providing enough physical space and controls allow for flexibility, reliability, and security in operating the automated SCADA network. This will enable the integration of remote devices will enable BVES to detect and react to faults, outages, and potential fire risk across its system. This upgrade project is a necessary component to upgrading the SCADA network.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
The Server Upgrade Project converts space at BVES into a fully compliant server room with security and environmental controls, backup power, server racks and conduit, and server equipment to fully support BVES's SCADA network.

Alternatives
There is no reasonable alternative as these upgrades are required to maintain and operate the SCADA network reliably, safely, and in meeting all associated compliance obligations.

***Region prioritization** ("where" to engage activity)*

The SCADA project will serve the entire service area.

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES has no recorded spend in 2021 supporting this initiative. The project is planned for 2023 and will have a projected spend (CAPEX) of $126,700 in 2023.

The RSE value for this initiative is 9.04.

Future improvements to initiative

No additional improvements are reflected in the planning stages of this initiative. BVES will apply any lessons learned throughout the progression of the program.

7.3.3.9.5 Distribution Management Center Program

***Risk to be mitigated** / problem to be addressed*

This initiative supports the SCADA network configuration, which aims to construct a fully equipped distribution management center to permit monitoring and control of the sub-transmission and distribution electrical assets, monitor and operate the OMS, update interactive voice response (IVR) and company website and social media, and provide for dispatch of repair crews. A fully integrated control management system is integral to maintaining optimal awareness into the system as well as management of communication methods internally and externally.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES plans to install a Distribution Management Control Center (DMCC) with the following equipment and applications that would provide substantially greater information capabilities to distribution decision makers relevant to the following functional areas: (1) Energy Resources; (2) T&D Assets; (3) SCADA, Outage Management System, GIS & Other Applications; (4) Weather Information; (5) HD Cameras; (6) Media Access (Internet, BVES Website & Social Media, Local Radio, TV, etc.); (7) Communications Equipment; and (8) Dispatch Services. The conceptual planning for such a facility is scheduled to start in 2024. A detailed design plan will be developed in 2023 with the facility anticipated to be constructed in 2024 to coincide with the SCADA and Grid Automation efforts being completed as the DMCC facility comes online.

Alternatives
There is no reasonable alternative considered for this initiative at this time.

***Region prioritization** ("where" to engage activity)*

The DMCC project will serve the entire service area.

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

Progress on initiative

BVES has no recorded spend in 2021 supporting this initiative. The project is planned for 2024 and will have a projected spend (CAPEX) of $37,400 in 2024.

The RSE value for this initiative is 30.8.

Future improvements to initiative

No additional improvements are reflected in the planning stages of this initiative. BVES will apply any lessons learned throughout the progression of the program.

BVES exchanges best practices on distribution management and SCADA control with other utilities and will implement changes as applicable. BVES will also explore the latest in distribution management practices by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest distribution management practices in T&D literature and periodicals.

7.3.3.10 Maintenance, repair, and replacement of connectors, including hotline clamps

This initiative covers the ongoing and routine O&M activities for **Connector Maintenance Repair and Replacement.**

BVES notes that hotline clamps are very rare in its system. In the 34 kV sub-transmission system, there are currently no hotline clamps installed. In the 4 kV system, hotline clamps have not been used for many years. Due to the voltage of the system, connectors can be installed using gloved techniques. With the gloved technique being a viable option, BVES avoids hotline clamping connector instillation in the 4 kV system.

Risk to be mitigated */ problem to be addressed*

This activity addresses the remediation, adjustments, or installation of new equipment to improve or replace existing connectors, including hotline clamps. This maintenance of equipment aims to improve the ability to protect electrical circuits from damage or ignition caused by overload of electricity or short circuit.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES must routinely maintain these electrical assets to prevent ignition risk through operations and maintenance practices. BVES does not have any hotline clamps on its sub-transmission system (34 kV) and does not have any hotline clamps in the HFTD Tier 3. Maintenance is achieved through the following inspections:

- Detailed asset inspections
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

Hotline clamps are rarely found in the BVES system. Because distribution voltage is 4 kV; generally, hotline clamping is not necessary.

Currently, it is BVES's policy that when a hotline clamp is found, to document its presence and replace it.

Alternatives
There are no other considered alternatives to these maintenance activities.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES does not have any hotline clamps in the HFTD 3.

BVES follows a replacement schedule aligned with other work such as those described in inspection schedules in **Section 7.3.4** Hotline clamps and other connectors will be maintained or replaced on an as needed basis and prioritized according to the relative risk.

Progress on initiative

In the next year, BVES will conduct this maintenance through electrical equipment inspections or other off-schedule activities as required. In the last five years, BVES replaced approximately six hotline clamps due to the limited number in its system and its efforts to not introduce any new additional hotlines as stated above. BVES policy requires Field Inspectors and Linemen to note and report any hotline clamp locations to the Field Operations Supervisor and Engineering staff for tracking in GIS system. Upon identification, the hotline clamp is identified for removal as soon as feasible. Once removed from the system, GIS is updated to reflect its removal.

The RSE value for this initiative is 45.9. BVES spent $8,774.93 (OPEX) in 2021 covering the regions of Tier 2 and Tier 3. Anticipated spend (OPEX) for this initiative is $12,700 in 2022, $13,100 in 2023, and $13,500 in 2024.

Future improvements to initiative

BVES will continue to track existing hotline clamps and when identified during inspection remove them as soon as feasible. BVES will apply any lessons learned throughout the progression of the maintenance program. It is BVES's plan to eliminate any hotline clamps discovered in its system.

7.3.3.11 Mitigation of impact on customers and other residents affected during PSPS event

This initiative covers the **Bear Valley Energy Storage Facility** (**7.3.3.11.1**) and the **BVPP Phase 3 and 4 Upgrade Project** (**7.3.3.11.2**).

7.3.3.11.1 Bear Valley Energy Storage Facility

***Risk to be mitigated** / problem to be addressed*

This program is aimed at reducing the impacts of power outages from proactive de-energization, increasing system resiliency, and preserving essential services.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES proposes to construct an energy storage project of approximately 5 MW/20 MWh (four-hour) Lithium-Ion NMC utility-grade battery in the BVES service area. This project will complement the Bear Valley Solar Energy Project (BVSEP), 5 MW alternating current single-axis tracker solar generation facility, to be constructed on the same location as the storage facility project and directly feeding the distribution system benefiting all customers. One of the purposes of the storage project is to minimize the impact of the loss of all SCE energy imports to the BVES service area due to a SCE-directed PSPS of the SCE supply lines to BVES. BVES imports from SCE are subject to PSPS and while these lines may be required to be de-energized by SCE, the BVES service area may not require PSPS. If these proposed

projects are approved, they will allow BVES to internally supply energy to most of its customers by utilizing its existing peaking power plant (8.4 MW), along with the BVSEP and the energy storage battery to minimize the effects of any PSPS event.

Alternatives

BVES considered multiple battery technologies and applications through a cost-benefit analysis study followed with a storage reliability study in recent years. Due to market saturation, industry demonstration, and forecasted reduction in storage device costs, BVES anticipates deploying lithium-ion technology. One possible alternative to the energy storage project is an expansion of a contemplated solar power project. Although an expansion would increase the amount of renewable energy available during daylight hours, the expanded solar project would not provide energy outside of daylight hours, requiring additional power resources to cover load during such periods. The energy storage concept, with its ability to provide energy during non-daylight hours, coupled with the solar power project, provided the best power-resource alternative.

Region prioritization *("where" to engage activity)*

BVES experienced delays in site location selection and will continue effort in locating the device site plans within 2022. Depending on unforeseen delays in locational siting of the facility or system design, BVES may anticipate another delay of up to one year prior to receiving operations. The site location will be strategically placed to optimize energy storage and dispatch during outages affecting customers surrounding the lake.

Project work is selected and sequenced per the process identified in **Section 7.1** “WMP Project Selection and Prioritization Process” and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES has no reported spend in 2021 and site location for the project is not finalized.

This project is still in development. BVES continues with project planning and made necessary refinements. BVES has not established the design of the project and only maintains preliminary comparison costs with no formal budget in place at this time.

The RSE value for this initiative is 0.24.

Future improvements to initiative

BVES is in the planning stages for this project and expects to file an application with the Commission for the energy storage project should it be determined that the project is in the best interest of BVES’s customers. In accordance with the 2020-2030 Integrated Resource Plan, BVES anticipated site development to begin tentatively in July 2022, however, this will likely be further delayed depending on the development and siting phase of the project as well as implementation of the BVSEP.

BVES exchanges best practices on energy storage with other utilities and will implement changes as applicable. BVES will also explore the latest in energy storage technology by attending energy storage conferences and meeting with other utilities and vendors. BVES will also review the latest energy storage technology in energy storage literature and periodicals.

7.3.3.11.2 BVPP Phase 3 and 4 Upgrade Project

Risk to be mitigated */ problem to be addressed*

This program is aimed at reducing the impacts of power outages from proactive de-energization and preserving essential services by improving the reliability of the Bear Valley Power Plant (BVPP).

Initiative selection *("why" engage in activity)*

"why" engage in activity

BVES proposes the Phase Three (2022) upgrades, which will include installing new catalyst housing directly above the engine. New placement will reduce heat loss and improve emissions bandwidths. The catalyst housing will include the double stacked element system to provide additional assistance in meeting emissions requirements. It also relocates oil and water piping, battery boxes, and controller stands while increasing accessibility and safety. The project will also address several age-related issues and align each generator to limit vibrations and abnormal wear on the engine.

Phase Four activities (2023) will include installing updated engine controls on all engines to a current controls system that will allow efficient start/stop functions, consolidated controls, and synchronization monitoring. Also, the plan is to replace the Detonation Sensing Module (DSM) Controls on all engines with a detcon system that will allow for visual DSM monitoring and repair any faulty wiring. Lastly, the project is scheduled to replace the governor speed control systems on all engines with a ProAct system and EX Gen control.

Alternatives

BVES does not have any alternatives to consider in the upgraded design of the BVPP.

Region prioritization *("where" to engage activity)*

This project relates to the location site of the BVPP, which is in Tier 2. The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

This project is planned for 2022 and 2023. BVES selected the contractor through its procurement process and is ready to execute the project as scheduled. Projected spend (CAPEX) in 2022 is $498,700 and $561,500 in 2023.

The RSE value for this initiative is 0.94.

Future improvements to initiative

BVES has outlined the Phase Three (2022) and Four (2023) activities planned for this initiative in the above section. BVES will consider any future upgrades when these phases are completed.

BVES exchanges best practices on power plant maintenance with other utilities and will implement changes as applicable. BVES will also explore the latest in power plant maintenance and operations by attending power generation conferences and meeting with other utilities and vendors. BVES will also review the latest power plant maintenance practices in power generation literature and periodical.

7.3.3.12 Other corrective action

This initiative covers the **Safety and Technical Upgrades to Substations** (**7.3.3.12.1**) and the **Tree Attachment Removal Program** (**7.3.3.12.2**).

7.3.3.12.1 Safety and Technical Upgrades to Substations

***Risk to be mitigated** / problem to be addressed*

This initiative category accounts for the incremental repair, maintenance, and replacement work associated with substations to function safely, reliably, and properly to reduce increased ignition risk.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES recently converted the existing Palomino Substation from an overhead-type to a pad-mounted design with dead front SCADA-enabled. This will improve the safety, reliability, and efficiency of the substation by eliminating a wiring configuration that poses a safety and fire risk due to its exposure to the elements, such as vegetation contact. Additionally, BVES has replaced all of the substation equipment with enclosed pad mounted transformers, voltage regulators, re-closers, and bus work, further enhancing wildfire mitigation and reliability.

The existing Palomino substation had an overhead, open bus type design. Because of this design, vegetation (leaves, branches, trees, etc.) could contact the energized bus and could cause an ignition potentially leading to a wildfire or extensive power outage. The new substation design uses a pad-mount dead-front design with no exposed energized conductors or equipment., The new "no-possible-contact" design reduces the ignition risk to near zero, essentially the maximum reduction possible when compared to an open bus design combined with vegetation management.

Alternatives
There are no alternatives as effective as the enhancements utilized on the Palomino Substation upgrade project. Some improvements may be made by installing avian guards on exposed conductors but it is not nearly as effective as dead-front enclosed equipment. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

This work is performed in Tier 2 as there are no substations in Tier 3. BVES will prioritize this effort based on need and relative risk.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

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Progress on initiative

BVES was able to complete the technical upgrades on the Palomino project at the end of 2021. These upgrades described above moved the Palomino Substation to a near-zero ignition risk facility. BVES spent $95,320 (OPEX) and $1,674,580 (CAPEX) in 2021 on the upgrades.

Ongoing operational spend is forecasted as $97,600 in 2022, $100,600 in 2023, and a separate initiative on the Maltby Substation will be commencing in 2024 with (CAPEX) $1,777,500 and (OPEX) $103,600 budgeted.

The RSE value for this initiative is 5.97.

Future improvements to initiative

BVES plans, in 2024, to perform partial safety and technical upgrades to the Maltby Substation. This will include replacing overhead regulators with pad-mounted regulators, installing pad-mounted IntelliRupter switches, which will convert the substation to be fully underground, and lastly, updates to substation controls. BVES will also continue to exchange information with other utilities on the available substation upgrades and their cost versus risk benefits.

7.3.3.12.2 Tree Attachment Removal Program

Risk to be mitigated */ problem to be addressed*

This initiative captures the work to remove legacy service attachments and wires that are affixed to trees, replacing with structures and poles that are more fire resistant.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Tree attachments are pieces of electrical infrastructure fastened to trees instead of poles for infrastructure support. Although this infrastructure approach initially reduces costs, it inherently introduces ignition risk by holding energized wires in direct proximity to vegetation. For some time now, the practice of installing distribution and service lines using tree attachments has been prohibited for new installations. Given that BVES's service area is entirely located in HFTD Tiers 2 and 3, tree attachments have been recognized as high-risk circumstances, BVES has planned to remove all tree attachments by the end of 2026. Elimination of tree attachments will enhance the safety and reliability of the distribution system and reduce the risk of wildfires.

BVES had approximately 1,207 legacy tree attachment service connections in its service area (2019 inventory count), mostly located in USFS controlled areas. As of December 31, 2021, BVES has removed 563 tree attachments and installed 223 new poles. BVES estimates that the remaining 644 tree attachments will be removed by the end of 2026.

Alternatives
There are no alternatives to eliminating the wildfire risk of electrical equipment attached to trees. BVES proposed an increased rate of removal of such equipment, but intervenors objected. Intervenors and BVES agreed to the current removal rate, which was approved by the Commission in D.19-08-027. BVES believes the agreed rate of removal strikes an appropriate balance of cost and use of available resources considering the competing needs to implement other important wildfire mitigation programs.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES does not have any more tree attachments in the HFTD 3. BVES is executing this initiative across the entire distribution system prioritized based on risk and accessibility (permitting).

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES has removed 563 tree attachments as of December 2021. BVES plans to remove another 80 tree attachments in 2022.

BVES spent $274,190 (CAPEX) on the tree attachment removal program in 2021 covering the regions of Tier 2 and Tier 3. In 2022 BVES has a projected spend of (CAPEX) $661,800. In 2023, projected spend (CAPEX) is $605,611.60 and in 2024 it is $607,223.40.

The RSE value for this initiative is 1.83.

Future improvements to initiative

BVES does not have any specific future improvements identified at this time. BVES plans to remove approximately 100 tree attachments per year to meet the 2026 program schedule. BVES will apply any lessons learned throughout the duration of the program.

7.3.3.13 Pole loading infrastructure hardening and replacement program based on pole loading assessment program

This initiative covers the **Pole Loading Assessment and Remediation.**

Risk to be mitigated */ problem to be addressed*

In compliance with GOs 95 and 165, BVES has an ongoing program to assess and remediate noncompliant distribution poles that pose a fire risk. Since the entire BVES service area is in a HFTD Tier 2 and 3, any pole failure is considered a high fire risk. Big Bear is above 3000 ft sea level and is subject to heavy loading requirements. Overhead distribution lines are exposed to severe weather including heavy snow, ice, and high winds.

Initiative selection *("why" engage in activity)*

"why" engage in activity

GO 95 Rule 43.1 requires BVES to design, build, and maintain their overhead facilities to withstand foreseeable fire-wind conditions in the service territory. Poles that are not compliant with GO 95 safety factors will be identified, and the appropriate remediation will be designed and implemented. Meeting or exceeding the mandates of GO 95 is critical to mitigate wildfires. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and also at preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability. BVES plans to increase the rate at which poles are required to evaluated per GO 95 standards. By assessing poles and remedying failures at a faster rate, BVES can significantly reduce its fire risk.

Alternatives

There are no reasonable alternative approaches to reducing wildfire risk due to non-compliant poles other than adequately testing all poles and taking remedial action, where required. There are alternatives as to the rate in which pole testing is conducted. To promote efficiency and minimize duplication of work, and subject to the remediation time frames in GO 95, the rate of testing and resulting remediation designs may be integrated with other potential work proposed in the same area. It is more operationally efficient and cost effective to coordinate pole replacement work with other planned work. For example, it is duplicative to replace a single pole under the pole assessment and remediation program only to have it removed a few years later when the pole line is replaced, or the line is upgraded requiring pole replacements. In addition, the program may require a sufficient number of pole replacements on a single line or in a concentrated area that it is prudent to undertake a more comprehensive replacement design, as opposed to mere replacement of individual poles. The remediation work is performed by BVES and/or contractor resources based on available capacity, cost, and other related factors.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Therefore, BVES follows an inspection and maintenance schedule to target priority pole replacements and remediations.

Project work is selected and sequenced per the process identified in **Section 7.1** "WMP Project Selection and Prioritization Process" and the work process flowchart in **Section 7.3**.

Progress on initiative

BVES has evaluated 3,260 poles since 2018 (557 in 2021); 1,434 failed the inspection criteria; 967 poles were replaced and 120 remediated. Corrective action for the remaining poles that failed inspection is being undertaken. BVES is coordinating this project with its projects to replace bare wire with covered wire (34 kV and 4 kV systems) as there is significant synergy in executing the two together. BVES plans to achieve 100% completion of the schedule review for 2022.

BVES spent $1,727,520.85 (CAPEX) in 2021 on this program across the service territory within Tier 2 and Tier 3 HFTDs. BVES estimates a spend of (CAPEX) $1,216,159.60 in 2022 targeting 165 poles.

The RSE value for this initiative is 0.4.

Future improvements to initiative

BVES will continue with its goal of increasing the rate of the inspection and maintenance program schedule while also integrating this project with its covered wire project and other projects when evaluating poles for strength due to the significant synergies involved. With these program advancements, BVES hopes to increase its annual review target. BVES will apply any lessons learned throughout the progression of the program.

7.3.3.14 Transformer maintenance and replacement

This initiative covers all **Transformers Maintenance and Replacement Activities**.

Risk to be mitigated */ problem to be addressed*

This initiative category accounts for the incremental repair, maintenance, and replacement work associated with transformers to enable safe operational function and to reduce increased ignition risk.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES must routinely maintain these electrical assets through standard transformer operations and maintenance practices to prevent ignition risk mainly due to catastrophic failure.

BVES has 3,141 service transformers and performs the following operations and maintenance on them:

- Detailed asset inspections (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- Patrol asset inspection (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

BVES has 18 substation transformers and performs the following operations and maintenance on them:

- Periodic oil samples and analysis.
- Monthly GO 174 visual inspection (checking for oil leakage, casing bulging, casing corrosion and integrity) and recording of operating temperatures and oil level
- Periodic thermography (every 4 years)
- Periodic winding resistance tests (every 4 years)
- Current injection test (every 4 years)
- Insulation resistance test (every 4 years)
- Transformer turns ratio (every 4 years)
- Power factor testing (every 4 years)

Service transformers are replaced based on their condition as determined by the above operations and maintenance actions and if the load needs to be expanded on the transformer.

Similarly, substation transformers are replaced based on condition as determined by above operations and maintenance actions and generally as part of a major substation upgrade project.

Alternatives
Adopting a run-to-fail policy and neglecting operations and maintenance is the only other option. BVES does not believe this is a good approach; especially in the HFTD Tier 2 & 3 areas. Failures could be catastrophic, which could initiate an ignition which in turn could result in wildfire.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES does not have any transformers in the HFTD 3. Service transformer maintenance normally consists of taking oil samples on a routine basis and performing asset inspections. BVES performs these maintenance actions on all of its service transformers so there is no marginal benefit to prioritizing by area. For example, oil samples are taken on all transformers within a week span.

BVES follows a replacement schedule aligned with other work such as those described in inspection schedules in **Section 7.3.4**.

Progress on initiative

In the next year, BVES will conduct this maintenance through electrical equipment inspections or other off-schedule activities as discussed above. BVES is conducting major substation checks on three substations in 2022, this cost is captured in the substation grid hardening initiative.

BVES budgeted (CAPEX) $70,000 in 2022, $100,000 in 2023, and $103,000 in 2024. For OPEX projections, BVES estimates $13,300 in 2022, $13,700 in 2023, and $14,100 in 2024. There are no substation transformer replacements planned for 2022, 2023 and 2024.

The RSE value for this initiative is 7.26. BVES spent $12,827.60 (OPEX) in 2021 covering the regions of Tier 2 and Tier 3.

Future improvements to initiative

BVES exchanges best practices on transformer maintenance with other utilities and will implement changes as applicable. BVES will also explore the latest in transformer maintenance and operations by attending T&D conferences and meeting with other utilities and vendors. BVES will also review the latest transformer maintenance practices in T&D literature and periodical.

7.3.3.15 Transmission tower maintenance and replacement

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.3.16 Undergrounding of electric lines and/or equipment

BVES currently does not have any major undergrounding projects planned.

This initiative covers **Minor Undergrounding Upgrade Projects**.

Risk to be mitigated */ problem to be addressed*

This activity addresses the utility actions taken to underground (UG) electrical lines and equipment in accordance with GO 128. Converting circuits from overhead to underground nearly eliminates the risk of ignition and exists minimally surrounding the area where equipment resurfaces.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not have any major UG projects planned at this time. BVES conducts small undergrounding projects for new developments and services and minor upgrades to existing facilities. When feasible, BVES works to install UG facilities for new developments and services to reduce the number of overhead facilities and therefore the risk those facilities pose to wildfire. BVES also conducts small upgrades to existing UG facilities so that service is safe, reliable, and of high quality.

Alternatives
The alternative is to convert to bare conductor overhead facilities to covered conductor overhead facilities. **Sections 9.3** and **9.4** discuss the advantages and disadvantages of covered conductors and UG facilities. The major advantage of covered conductors is that they cost significantly less per circuit mile than UG facilities yet the marginal gain in risk reduction by utilizing UG instead of covered conductors is not nearly as significantly.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. Therefore, BVES would select a project that targets the highest risk circuits. The minor UG projects that BVES engages in are generally driven by the customer or local government and are generally new facilities; therefore, it is difficult to prioritize them by wildfire risk. However, as noted before, BVES's entire service area is extreme or elevated risk so any UG has a significant wildfire risk benefit.

Progress on initiative

There are no immediate plans for large-scale undergrounding projects in 2022. BVES will continue to conduct small UG projects driven by new developments and local government in 2022.

BVES spent $508,648.86 (CAPEX) in 2021 on this initiative activity and estimates a budgeted spend of $75,000 in 2022, $312,200 in 2023, and $309,000 in 2024. The RSE value for this initiative is 3.82.

Future improvements to initiative

BVES will continue to reassess the need of potential undergrounding projects and will continue to exchange information with the other utilities on the advantages and disadvantages of UG and covered conductors through working groups. BVES will watch carefully for any advances in UG installation, especially those that reduce the price point while maintaining GO 128 minimum specifications.

7.3.3.17 Updates to grid topology to minimize risk of ignition in HFTDs

This initiative is not currently active or otherwise captured under a different section.

Risk to be mitigated */ problem to be addressed*

This activity would incorporate any changes in plan, installation, construction, removal and/or undergrounding projects to minimize risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not have a unique activity associated with this initiative.

Alternatives
BVES does not have a unique activity associated with this initiative.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Therefore, BVES would select a project that targets the highest risk circuits.

Progress on initiative

BVES currently does not have a unique activity associated with this initiative; therefore, BVES has no recorded spend for this initiative activity. BVES does not have any plans in 2022 for this initiative.

Future improvements to initiative

BVES will continue to assess the need to implement work under this initiative activity and provide updates in a future WMP. Currently, BVES does not have future plans for this initiative.

7.3.4 Asset Management and Inspections

Asset Management and inspections consists of monitoring and maintaining the system. This includes conducting system patrols, leveraging technological inspections tools, and managing maintenance. BVES categorizes these activities into two types of initiatives: (1) System Inspection and Maintenance Plan (Inspections) and (2) Electrical Preventative Maintenance Program (PM Program). These are spread across the WMP initiative category in accordance with the activity definitions.

Inspections play an important role in wildfire prevention, as degraded equipment or encroaching vegetation may ignite a wildfire. BVES currently patrols its system regularly and has increased the inspection programs. The BVES Inspections include several components: detailed and patrol inspections of the sub-transmission and distribution system, substations equipment inspections, electrical preventative maintenance (PM), UAV aerial surveys (imagery and thermography) and LiDAR survey.

BVES PM Program is a condition based "preventive maintenance" (PM) program. The equipment is maintained, based on regular scheduled PM intervals. As a general rule, BVES does not conduct "run-to-failure" for its assets. The PM program assesses major equipment assets located at BVES substations and in the field at locations in the BVES sub-transmission (34.5 kV) and distribution (up to 4.160 kV) system. The results of the program are designed to evaluate the condition of key distribution equipment assets, identify equipment at risk of failure, improve performance, reduce costs, and extend equipment life. Most importantly, the program mitigates the risk of catastrophic failure of equipment, which could result in fire, public and worker safety hazards, environmental damage, prolonged unplanned outages, and costly repairs or replacement of equipment.

7.3.4.1 Detailed inspections of distribution electric lines and equipment

This initiative covers the **Detailed Inspection Program**.

***Risk to be mitigated** / problem to be addressed*

This initiative aligns with GO 165 requirement to conduct careful visual inspections of overhead electric distribution lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded. In these Detailed Inspections electrical facilities, lines and equipment carefully examined, visually, and discrepancies are recorded. This inspection is thorough and more time-consuming than Patrol Inspections. Individual pieces of equipment and structures are carefully examined to determine the condition of each rated and recorded component. Identifying equipment degradations is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to equipment failure.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
A "detailed inspection" is a more careful visual and diagnostic exam of individual pieces of equipment. The inspector records the results of the diagnostic and visual examinations and rates the condition of the equipment. These inspections are designed to identify any existing, including minor, defects. These may include, but are not limited to, open wire secondary clearance, corona effect on cross-arms, warning signage issues, visibility strips and pole-tag issues, and rotten poles. BVES conducts these inspections at least once every five years in compliance with GO 165 and GO 95 (Rule 18). If any defects are identified, BVES prioritizes the defect resolution based on risk and resolves the issues in compliance with GO 95 Rule 18 timeframes.

In compliance with GO 165, BVES's Inspection Program requires overhead facilities to be inspected per the Detailed Inspection process every five years. Detailed Inspections of assets are a critical element in mitigating the risk of wildfire caused by electric utility facilities. BVES divides its system up and each year conducts Detailed Inspections such that each circuit is Detailed Inspected at least every five years. BVES's Field Inspector performs the Detailed Inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines.

Detailed Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of Detailed Inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of Detailed Inspections as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of Detailed Inspections are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
The Detailed Inspections are a compliance activity required by GO 165 and must be performed. Detailed Inspections provide BVES with additional information on the electric distribution equipment and provides the ability to take corrective actions prior to an event that could cause a potential ignition.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform a Detailed Inspection of all its circuits every five years per GO 165. BVES divides this up into a five-year schedule that achieves the GO 165 requirement. On average, it takes the Field Inspector approximately 40 full workdays to conduct the annual portion of the Detailed Inspections of BVES's overhead facilities and power lines (not including documenting findings in the database). Therefore, not much risk reduction is gained by prioritizing higher risk areas over lower risk areas.

Progress on initiative

In 2022, BVES's target is to conduct 29 circuit miles of Detailed Inspections of the sub-transmission and distribution system per BVES's five-year Detailed Inspection program as required by GO 165. Additionally, BVES will be improving its asset GIS database information with mobile device data acquisition. The BVES Field Inspector is working closely with the software developers to ensure the software is customized to BVES's requirements which include compliance with GO 95 and GO 165.

BVES spent $8,177.86 (OPEX) in 2020 covering Tier 2 and Tier 3 HFTDs. BVES achieved 100 percent of planned detailed inspections in 2021. BVES has budgeted $8,400 in 2022, $8,700 in 2023, and $8,900 in 2024. The RSE value for this initiative is 34.7.

Future improvements to initiative

BVES will continue to cross check the effectiveness of its Detailed Inspections by validating the results with other asset inspections (Patrol Inspections, LiDAR, UAV imagery & thermography, third-party ground patrol inspections, etc.) to improve its detailed inspection techniques. BVES will also exchange information with other utilities to determine best practices in asset detailed inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of improving it GIS database with asset inspection information, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of Detailed Inspection results to determine if systemic issues are impacting BVES's system with respect to asset failure or degradation.

7.3.4.2 Detailed inspections of transmission electric lines and equipment

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.4.3 Improvement of inspections

This initiative covers **Improvement of Electrical Inspection Procedures**.

Risk to be mitigated */ problem to be addressed*

This initiative includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This will support improvement of training and applying lessons learned from third party evaluations and inspections.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors is critical to ensure asset inspections are of high quality. Asset inspection is a critical element for mitigation of wildfire. BVES maintains routine training and assessment of electrical inspection activities. BVES also applies annual lessons learned or identified improvements and tracks developing inspection practices in the industry.

Alternatives
There are no alternatives to this initiative apart from meeting current GOs and utility inspection standards.

Region prioritization *("where" to engage activity)*

Because asset inspections are required in all areas of the service area and generally asset inspection improvements are not specific to certain areas, the improvement efforts will not only benefit the higher risk areas but the entire service area.

Progress on initiative

Current plans for next year include procuring and implementing iRestore inspection software to improve collection, management, and review of inspection results. The improvements include mobile device data acquisition, documentation of asset inspection findings, assignment of resolution priority, tracking status of resolution, and high-level finding analysis to determine if systemic issues exist.

BVES spent $19,870.12 (OPEX) in 2021 covering improvements to inspection practices performed throughout the year within HFTD Tier 2 and Tier 3.

Projected costs (CAPEX) in 2022 are estimated to be $130,000. OPEX projections in 2022 are budgeted as $20,400. In 2023, BVES plans to spend (OPEX) $21,000 and $21,600 in 2024.The RSE value for this initiative is 28.56.

Future improvements to initiative

BVES will monitor the results of its asset management inspection programs and implement improvements as warranted. BVES will also exchange information with other utilities to determine best practices in asset management improvements for consideration in BVES's program. Furthermore, BVES is in the process of implementing asset management inspection software, which will enhance the ability to analyze the results of asset management inspections.

7.3.4.4 Infrared inspections of distribution electric lines and equipment

This initiative covers the **Infrared Inspection Program // UAV Thermography**.

Risk to be mitigated */ problem to be addressed*

This initiative includes inspections of overhead electric distribution lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment. The inspection is conducted utilizing thermographic imaging equipment mounted on a UAV and conducting an aerial survey of BVES's sub-transmission and distribution facilities and power lines. This inspection exceeds the requirements mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept. This relatively quick and accurate inspection will allow BVES to verify, document and resolve potential equipment degradations, overheating, and/or failures by recording "hot spots" and then investigation further each hot spot by careful visual inspection. Following the UAV flight, crews visit each hot spot and conducted a thorough and careful examination of the equipment, taking corrective action, as applicable, to resolve the issue.

Initiative selection *("why" engage in activity)*

"why" engage in activity
No comparable alternative exists. The UAV thermographic survey provides quick and meaningful inspection results other inspection methods are not able to provide. The ability to identify "hot spots" is unique to this inspection technology. Generally, thermographic hot spots are indicative of potential equipment degradation or failure.

Thermography survey findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action. When BVES receives the thermography survey report, each finding is investigated by qualified personnel in evaluating asset conditions to validate the identified conditions and reassign the priority per GO 95, if deemed appropriate. The thermography contractor will immediately inform BVES of any level 1 findings so that they may be corrected or resolved to a level 2 or 3 finding as soon as possible.
The Wildfire Mitigation and Reliability Engineer reviews the results of thermography surveys and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the result of thermography surveys as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of thermography surveys are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
BVES could consider forgoing this inspection beyond compliance requirements, but at this time BVES considers this inspection a valuable wildfire mitigation initiative that provides visibility of potential ignition hazards that other inspection methods may not detect such as equipment degradation and potential failures. Infrared electrical testing allows for inspection of a large amount of electrical equipment in a short time as opposed to the alternative method of physically inspecting electrical components.

Alternatives for this activity include ground-level inspections, which may include visual and detailed evaluation of equipment conditions. The benefits from infrared imaging include granular awareness into potential failures as images highlight areas of degradation. There are no directly applicable alternatives to the value gained from implementing this activity.

***Region prioritization** ("where" to engage activity)*

BVES performs a UAV Thermography survey of all of its circuits each year. It takes its an expert contractor approximately six weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much risk reduction could be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the UAV Thermography Survey prior to the fire season Santa Ana wind period.

Progress on initiative

In 2021, BVES initiated UAV thermography (aerial) component of this initiative, which will continue each year. BVES completed 211 circuit miles of inspection under this component of the initiative. In 2022, BVES's target is to conduct a UAV Thermographic Survey of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. Additionally, BVES will be implementing improved asset inspection data in its GIS and will work on including the inspection findings into the inspection GIS database.

BVES spent (OPEX) $53,377.50 in 2021 on ongoing UAV HD Photography/Videography Survey. The RSE value for this initiative is 3.24.

BVES will be continuing annual inspections with UAV HD Photography/Videography Survey with anticipated (OPEX) spend of $59,400 in 2022, $59,400 in 2023, and $61,200 in 2024. These costs are equally spread between the electrical inspection activities, as they are performed concurrently.

Future improvements to initiative

BVES will continue to evaluate the effectiveness of the UAV Thermography Surveys by crosschecking the results with other asset inspections (Detailed Inspections, Patrol Inspections, LiDAR, UAV Photographic/Videography Imagery, 3rd Party Ground Patrol Inspection, etc.) to improve UAV imagery inspection techniques. BVES will also exchange information with other utilities to determine best practices in asset UAV Thermographic survey techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing improved GIS database enhancements, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to asset performance.

7.3.4.5 Infrared inspections of transmission electric lines and equipment

This is not an applicable initiative.

***Risk to be mitigated** / problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

***Region prioritization** ("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.4.6 Intrusive pole inspections

This initiative covers the **Pole Loading Assessment and Remediation Program // Intrusive Pole Inspection Program**.

***Risk to be mitigated** / problem to be addressed*

In accordance with GO 165, this initiative monitors the age and structural integrity of existing wood poles through means of a more detailed assessment of the pole’s condition such as coring areas of identified damage and visual inspection of the poles apart from pole loading assessments results.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES performs intrusive pole inspections on a cycle that meets GO 165 requirements. Intrusive inspections involve movement of soil, taking samples for analysis, and using more sophisticated diagnostic tools beyond visual inspections of instrument reading. Wood poles over 15 years which have not been subject to intrusive inspection are due for inspection in 10 years. Wood poles which passed intrusive inspection are due every 20 years. When the inspection determines the pole no longer has the required strength, the pole is scheduled for replacement. This program determines the health of existing poles. BVES routinely intrusively inspects poles as part of its Pole Loading and Assessment program and performs directed intrusive inspections as needed.

Alternatives
No comparable alternative exists. Intrusive pole inspections are mandated by GO 165. These inspections are completed throughout the BVES service territory. BVES tracks conditions found during the intrusive pole inspections and replaces defective poles as required. There are no identified alternatives to these intrusive inspection practices.

***Region prioritization** ("where" to engage activity)*

BVES generally performs a number of intrusive pole inspections each year as directed by the engineering group which keeps track of each pole, when it was last intrusively inspected, and previous intrusive inspection findings. BVES must ensure all wood poles are compliant with GO 165 intrusive inspection requirements regardless of where the pole is located. While BVES must inspect all of its poles in accordance with GO 165's inspection, BVES prioritizes higher risk areas (i.e., Tier 3 areas and circuits identified as elevated risk) to maximize the risk reduction of this initiative.

BVES also prioritizes completing the annual designated set of intrusive inspections prior to the fire season Santa Ana wind period.

Progress on initiative

In 2021, BVES achieved its intrusive pole target of intrusively inspecting poles 850 by inspecting 876 poles. For 2022, the BVES target is to intrusively inspect at least 850 poles. Additionally, the goal will be to complete these inspections before the fire season Santa Ana winds.

BVES spent (OPEX) $30,512.31 in 2021 on this initiative activity intrusively inspecting 876 poles. 28 of those poles failed the intrusive pole inspection.

BVES plans to perform intrusive pole inspections on 850 poles in 2022, 2023 and 2024. Projected spend (OPEX) in 2022 is $33,000, $35,000 in 2023, and $36,100 in 2024.

The RSE value for this initiative is 17.7.

Future improvements to initiative

BVES will exchange information with other utilities to determine best practices in asset intrusive pole inspection techniques for consideration in BVES's inspection program. Additionally, BVES is working on improving its GIS database for asset inspection results and asset conditions. This effort includes the intrusive pole inspection data and will allow high level analysis of intrusive pole inspection results, alerting when poles are coming due, and the ability to track the status of resolving intrusive pole inspection findings.

7.3.4.7 LiDAR inspections of distribution electric lines and equipment

This initiative covers the **LiDAR Inspection Program for Equipment Inspections**.

Risk to be mitigated */ problem to be addressed*

This initiative involves inspections of overhead electric distribution lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances) to identify asset degradations and other potential failure mechanism.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES conducts one LiDAR sweep of its entire service area per year to evaluate the effectiveness of clearance efforts and identify potential wildfire hazards. This is an enhanced inspection using LiDAR (Light Detection and Ranging) inspections and analysis, which uses a system of lasers and software to develop surveys of the overhead sub-transmission and distribution systems, to accurately determine vegetation clearances to conductors. BVES began using LiDAR through a pilot project initiative using both helicopter and fixed wing flights, as well as via a truck-mounted mobile system. Given the proximity of the majority of BVES's electrical system to the road network and the tree canopy that is typical of distribution systems, truck-mounted mobile LiDAR is utilized more often because it is more effective.

LiDAR survey findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations

Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action. When BVES receives the LiDAR survey report, each finding is investigated by qualified personnel in evaluating asset conditions to validate the actual conditions and reassign the priority per GO 95, if deemed appropriate. The LiDAR contractor immediately informs BVES of any level 1 findings so that they may be corrected or resolved to a level 2 or 3 finding as soon as possible.

The Wildfire Mitigation and Reliability Engineer reviews the results of LiDAR surveys and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of LiDAR surveys as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of LiDAR surveys are validated against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives

No comparable alternative exists. The LIDAR pilot project was able to detect potential wildfire ignition hazards sources and is considered a success at mitigating potential ignition sources. Consequently, BVES will continue to perform one LIDAR inspection per year as an on-going program.

Additionally, LiDAR use at other utilities over the past years as demonstrated the significant value of this inspection technique. Consequently, BVES will continue to perform one LIDAR inspection per year as an on-going program.

Region prioritization *("where" to engage activity)*

BVES performs a LiDAR survey of all circuits each year. It takes its expert contractor approximately two weeks to gather LiDAR data on the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much additional risk reduction could be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the LiDAR inspection prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES's target is to conduct a LiDAR survey of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. Additionally, BVES will be implementing improvements to its asset inspection and condition GIS database and will work on how to merge LiDAR data files into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES's requirements to include LiDAR survey results.

BVES spent $59,560.00 (OPEX) in 2021 with a contracted vendor covering the entire sub-transmission and distribution system. Projected spend in 2022 is $65,000 in 2022, $66,500 in 2023, and $68,500 in 2024. The RSE value for this initiative is 4.91.

BVES will continue with an annual inspection in 2022 and apply any lessons learned.

Future improvements to initiative

BVES will evaluate combining LiDAR efforts with UAV HD imagery and thermography efforts where the tree canopy allows use of UAVs for LiDAR data acquisition. BVES will continue to monitor the effectiveness of the truck-mounted mobile system for the LiDAR inspection program.

BVES will continue to cross check the effectiveness of its LiDAR surveys by validating the results with other asset inspections (Detailed Inspections, Patrol Inspections, UAV Imagery, UAV Thermography, 3rd

Party Ground Patrol Inspections, etc.) to improve LiDAR survey techniques. BVES will also exchange information with other utilities to determine best practices in asset LiDAR survey techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing improvements to is asset inspection and condition GIS database, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of LiDAR inspection results to determine if systemic issues are impacting BVES's system with respect to asset degradations.

7.3.4.8 LiDAR inspections of transmission electric lines and equipment

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.4.9 Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations

This initiative covers the **Detailed Inspection Program** (7.3.4.9.1) and **UAV HD Photography Inspection Program** (7.3.4.9.2).

7.3.4.9.1 Third Party (Second) Ground Patrol – Detailed Inspection Program

Risk to be mitigated */ problem to be addressed*

BVES conducts an additional independent (3rd Party) patrol inspection beyond that required by GO 165 of the entire overhead system, so that two visual patrols of the entire overhead system are conducted annually. The 3rd Party Ground Patrol Inspection is a second patrol inspection conducted in accordance with GO 95 and GO 165 standards by a third-party independent contractor. The 3rd Party Ground Patrol Inspection is a careful, visual inspection of overhead electric distribution lines and equipment along rights-of-way designed to identify obvious hazards. This includes carefully examining individual pieces of equipment and structures to determine the condition of each rated and recorded component along with vegetation clearances to bare conductor. Identifying equipment degradations, failures, and/or vegetation encroachments to minimum clearance requirements (as established by GO-95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES believes this additional patrol is warranted due to the local climate; likelihood of icing conditions; tree limbs and branches subject to weakening due to repeated high winds, snow, and ice weight (which may cause fatigue failure); high elevation; other local conditions; difficultly accessing vegetation for trimming near bare conductors; species growth rates and characteristics; and the fact that the service area is designated “very dry” or “dry” approximately 80 percent of the time in the NFDRS. This environment, coupled with the fact that the fire season is now year-round, creates a high-risk condition that can be mitigated by increasing patrols. Substandard conditions detected on the second ground patrol are addressed in the same manner as the first patrol in compliance with GO 95 and 165.

GO 165 requires overhead facilities to be patrol inspected each year. A "patrol inspection" is a visual inspection designed to identify obvious problems, gross defects, and hazards. Gross defects may include, but are not limited to, cracked cross-arms, poles leaning beyond specification, guy wires missing or damaged, vegetation encroachment inside of minimum clearance standards, etc. These encroachments have the potential to spark and ignite a wildfire. Patrol inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities.

This inspection conducted by a contracted 3rd party satisfies GO 165 patrol inspection requirements and is in effect an additional annual GO 165 patrol inspection to the one that the BVES’s Field Inspector performs. BVES contracts experienced and qualified electrical distribution asset inspection contractors to perform this ground patrol inspection.

3rd Party Ground Patrol Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS data base. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of the 3rd Party Ground Patrol Inspections are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
BVES could consider forgoing this inspection beyond compliance requirements but at this time BVES considers this inspection a valuable wildfire mitigation initiative. There are no other considered alternatives at this time.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES’s service area is small (32 square miles). Additionally, BVES’s HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES performs a 3rd Party Ground Patrol Inspection of all of its circuits each year. It takes its expert contractor approximately three weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, little risk reduction can be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the 3rd Party Ground Patrol Inspection prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES's target is to conduct a 3rd Party Ground Patrol Inspection of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. Additionally, BVES will be implementing improved asset inspection and condition GIS database enhancements and will work on including the inspection findings into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES's requirements to include the inspection results.

BVES spent $15,930 in 2021 on this activity. BVES has budgeted (OPEX) $40,000 in 2022, $41,500 in 2023, and $42,700 in 2024. The RSE value for this initiative is 6.51.

Future improvements to initiative

BVES will continue to cross check the effectiveness of the 3rd Party Ground Patrol Inspections by validating the results with other asset inspections (Detailed Inspections, Patrol Inspections, LiDAR, UAV Imagery, UAV Thermography, etc.) to improve patrol inspection techniques. BVES will also exchange information with other utilities to determine best practices in asset patrol inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to asset degradations.

7.3.4.9.2 UAV HD Photography Inspection Program

Risk to be mitigated */ problem to be addressed*

This initiative uses a high definition (HD) imagery aerial survey of BVES's sub-transmission and distribution facilities and power lines inspection of rights-of-way, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, and other aspects of inspection and record keeping. This relatively quick and accurate inspection allows BVES to verify, document and resolve asset degradations and failures before they may cause ignitions.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES will contract UAV fly-over inspections of its sub-transmission and distribution system. This inspection complements the ground patrols and detailed inspections of GO 165 and LiDAR inspections. Many electric utilities including major California electric utilities have found inspections utilizing UAVs are highly effective at identifying facilities degradations and issues that ground patrols and detailed inspections would not necessarily reveal. The UAVs film the facilities using high-definition video photography while maintaining an accurate date/time and geolocation stamp on the recorded video stream. The video recordings are then reviewed by qualified analysts who are able to slow down the recording so as to note any issues. When a potential issue is identified, they can freeze the video and

perform further analysis such as zooming in on the item in question. Discrepancies are then identified, evaluated, recorded, and remediation or further investigation is assigned.

The UAVs used for this inspection will also collect infrared thermography data for analysis. This technology includes heat-sensing cameras that can identify risk drivers such as increased “hot” areas or conditions that may indicate deterioration, which can lead to potential failures and ignitions.

UAV Imagery findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of the UAV Imagery surveys and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of the UAV Imagery surveys as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of the UAV Imagery surveys are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives

No comparable alternative exists. The UAV Imagery survey provides quick and meaningful inspection methods are not able to provide. The top-down view and the ability to zoom into facilities with high-definition imagery allows data analysists to identify and pinpoint asset degradation issues with high fidelity that frequently are not visible through routine patrol inspections or even detailed inspections. Obviously, the tree canopy can be an impediment, but overall, the benefit of the UAV Imagery survey is an effective element of inspection necessary to mitigate wildfire.

Region prioritization *("where" to engage activity)*

BVES performs a UAV HD Photography/Videography survey of all of its circuits each year. It takes an expert contractor approximately six weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much risk reduction could be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the UAV HD Photography/Videography Survey prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES’s target is to conduct a UAV HD Photography/Videography Survey of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. This will be the second year BVES has performed this type of inspection. Additionally, BVES will be implementing a new inspection application and will work on including the inspection findings into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES’s requirements to include the inspection results.

BVES spent (OPEX) $53,377.50 in 2021 on ongoing UAV HD Photography/Videography Survey. The RSE value for this initiative is 3.24.

BVES will be continuing annual inspections with UAV HD Photography/Videography Survey with anticipated (OPEX) spend of $59,400 in 2022, $59,400 in 2023, and $61,200 in 2024. These costs are equally spread between the electrical inspection activities, as they are performed concurrently.

Future improvements to initiative

BVES will continue to cross check the effectiveness of the UAV HD Photography/Videography Survey by validating the results with other asset inspections (Detailed Inspections, Patrol Inspections, LiDAR, UAV Thermography, 3rd Party Ground Patrol Inspection, etc.) to improve UAV imagery inspection techniques. BVES will also exchange information with other utilities to determine best practices in asset UAV imagery survey techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing asset inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of UAV Imagery inspection results to determine if systemic issues are impacting BVES's system with respect to asset degradations.

7.3.4.10 Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.4.11 Patrol inspections of distribution electric lines and equipment

This initiative covers the **Ground Patrol Inspection Program**.

Risk to be mitigated */ problem to be addressed*

This initiative aligns with GO 165, which requires utilities to execute careful, visual inspections of overhead electric distribution lines and equipment along rights-of-way that is designed to identify obvious hazards. This includes individual pieces of equipment and structures that are carefully examined to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying asset degradations and/or failures is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to equipment failure.

Initiative selection *("why" engage in activity)*

"why" engage in activity
In compliance with GO 165, BVES's Inspection Program requires a patrol inspection of all overhead facilities each year. A "patrol inspection" is a visual inspection designed to identify obvious problems, gross defects, and hazards. Gross defects may include, but are not limited to, cracked cross-arms, poles leaning beyond specification, guy wires missing or damaged, vegetation encroachment inside of minimum clearance standards, etc. These encroachments have the potential to spark and possibly ignite a wildfire. Patrol inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities. BVES's Field Inspector performs the patrol inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines.

Patrol Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of patrol inspections are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
Patrol inspections are a compliance activity required by GO 165 and must be performed. Patrol inspections provide BVES with additional information on the electric distribution equipment and provides the ability to take corrective actions prior to an event that could cause a potential ignition.

Region prioritization *("where" to engage activity)*

BVES is required to perform a patrol inspection of all of its circuits each year per GO 165. It takes the Field Inspector approximately 20 full workdays to conduct a patrol of BVES's 211 circuit miles of overhead facilities and power lines (not including documenting findings in the database). Therefore, not much additional risk reduction is gained by prioritizing higher risk areas over lower risk areas. However, BVES believes there is value in conducting additional patrols (more than once per year) in high-risk areas; especially when environmental conditions are more prone to wildfire risk. High risk areas are patrolled prior to the fire season.

Progress on initiative

In 2022, BVES's target is to conduct a patrol inspection of the entire sub-transmission and distribution system (211 circuit miles) as required by GO 165. Additionally, BVES will be implementing a new inspection application with mobile device data acquisition. The BVES Field Inspector is working closely with the software developers to ensure the software is customized to BVES's requirements which include compliance with GO 95 and GO 165.

BVES spent $19,081.67 (OPEX) on this initiative in 2021 and will continue with ongoing inspection schedules in 2022. BVES budgets (OPEX) $19,700 in 2022, $20,200 in 2023, and $20,900 in 2024. The RSE value for this initiative is 14.8.

Future improvements to initiative

BVES will continue to cross check the effectiveness of its patrol inspections by validating the results with other asset inspections (Detailed Inspections, LiDAR, UAV Imagery, 3rd Party Ground Patrol Inspections, etc.) to improve its patrol inspection techniques. BVES will also exchange information with other utilities to determine best practices in asset patrol inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing asset inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to asset degradations.

7.3.4.12 Patrol inspections of transmission electric lines and equipment

This is not an applicable initiative.

***Risk to be mitigated** / problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

***Region prioritization** ("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.4.13 Pole loading assessment program to determine safety factor

This initiative covers the **Pole Loading Assessment and Remediation Program**.

***Risk to be mitigated** / problem to be addressed*

The recorded activity complements **Section 7.3.3.13** in determining deficiencies and remediation needs for pole maintenance and replacement work.

In compliance with GOs 95 and 165, BVES has an ongoing program to assess and remediate noncompliant distribution poles that pose a fire risk. Since the entire BVES service area is in a HFTD Tier 2 and 3, any pole failure is considered a high fire risk. Big Bear is above 3,000 ft sea level and is subject to heavy loading requirements. Overhead distribution lines are exposed to severe weather including heavy snow, ice, and high winds.

Initiative selection *("why" engage in activity)*

"why" engage in activity
GO 95 Rule 43.1 requires BVES to design, build, and maintain their overhead facilities to withstand foreseeable fire-wind conditions in the service territory. Poles that are not compliant with GO 95 safety factors will be identified, and the appropriate remediation will be designed and implemented. Meeting or exceeding the mandates of GO 95 is critical to mitigate wildfires. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and also at preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability. BVES plans to increase the rate at which poles are required to be evaluated per GO 95 standards. By assessing poles and remedying failures at a faster rate, BVES can significantly reduce its fire risk.

As of December 31, 2021, and presented in the Q4 QDR, BVES has evaluated 3,260 poles since 2018 (557 in 2021); 1,434 failed the inspection criteria; 967 poles were replaced and 120 remediated. Corrective action for the remaining poles that failed inspection is being undertaken. This is an ongoing project with the initial program period expected to be completed by the end of 2022. BVES is coordinating this project with its projects to replace bare wire with covered wire (34 kV and 4 kV systems) as there is significant synergy in executing the two together.

Alternatives
There are no reasonable alternative approaches to reducing wildfire risk due to non-compliant poles other than adequately testing all of the poles and taking remedial action, where required. There are alternatives as to the rate in which pole testing is conducted. In order to promote efficiency and minimize duplication of work, and subject to the remediation time frames in GO 95, the rate of testing and resulting remediation designs may be integrated with other potential work proposed in the same area. It is more operationally efficient and cost effective to coordinate pole replacement work with other planned work. For example, it is duplicative to replace a single pole under the pole assessment and remediation program only to have it removed a few years later when the pole line is replaced, or the line is upgraded requiring pole replacements. In addition, the program may require a sufficient number of pole replacements on a line or in a concentrated area that it is prudent to undertake a more comprehensive replacement design, as opposed to mere replacement of individual poles. The remediation work is performed by BVES and/or contractor resources based on available capacity, cost, and other related factors.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. BVES must perform Pole Loading Assessments across in accordance with GO 95. This work is performed on a cycle, but BVES may adjust the cycle to address higher risk areas on an as needed basis or in coordination with other initiative activity.

Progress on initiative

BVES spent $90,920 (CAPEX) in 2021 on this program across the service territory within Tier 2 and Tier 3 HFTDs.

BVES plans to continue this project in high-risk areas and close out the program 2022 when it will be merged as a component of the covered wire program. Because covered wire installation requires pole loading and assessment and because covered wire is being installed on the highest risk circuits first, there is significant synergy in combining the two workflows.

The projected spend for 2022 is $64,000 (CAPEX). The RSE value for this initiative is 0.4.

Future improvements to initiative

BVES will integrate this project with its covered wire project and other projects to involve evaluating poles for strength due to the significant synergies involved. BVES will apply any lessons learned throughout the progression of the program.

7.3.4.14 Quality assurance / quality control of inspections

Revised to address RN-BVES-22-04: BVES has not provided sufficient information on quality assurance & quality control (QA/QC)

This initiative covers **Inspection Improvement Activities // QA/QC Activities**.

Risk to be mitigated */ problem to be addressed*

This initiative includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This will support improvement of training and applying lessons learned from third party evaluations and inspections. The initiative establishes an audit process to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This initiative includes the identification of deficiencies and actionable outcomes to improve inspection protocols executed in the field. This will support improvement of work outcomes, training of personnel involved in asset management, and applying lessons learned from internal and external evaluations and audits.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Asset management to achieve properly operating equipment and facilities is vitally important for enhancing public safety and mitigating the threat of wildfire. Therefore, establishing an asset management quality assurance (QA) and quality control (QC) program is a critically essential element of a successful asset management program that aims to assure intended contractors' scope of work outcomes and asset management continuous process improvement.

Alternatives
There are no alternatives to this activity apart from meeting current GOs and utility inspection standards.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. BVES is required to perform asset management by GOs and applicable standards across the service area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas.

Progress on initiative

BVES spent $19,870 (OPEX) in 2021 to improve inspection practices performed throughout the year within HFTD Tier 2 and Tier 3. In 2021, BVES developed a formal QA/QC program for asset inspection.

Table 7.3-4 below demonstrates the quality control program tracking.

Table 7.3-4: Example Quality Control Program Tracking

Start Pole #	End Pole #	Start STA #	End STA #	New Wire Size	Total Circuit Length	Conductor Qty	Circuit	Install Date	CM	BVES QC Date	BVES Inspector	BVES QC Personnel
12439BV	11918BV / 14278BV	60	69-70	394	1250	3	Shay 34kV	6/10/2021	0.24	6/11/2021	Field Inspector	Anthony Rivera
12439BV	11918BV / 14278BV	60	69-70	394	1250	4	Pioneer 4kV	6/10/2021	0.24	6/11/2021	Field Inspector	Anthony Rivera
12447BV	14824BV	78	82-83	1/0	525	2	Pioneer 4kV	6/24/2021	0.10	6/25/2021	Field Inspector	Anthony Rivera
14826BV	14828BV	91	94-95	1/0	575	2	Pioneer 4kV	6/24/2021	0.11	6/25/2021	Field Inspector	Anthony Rivera
11298BV	12439BV	60	61	1/0	60	2	Pioneer 4kV	6/10/2021	0.01	6/11/2021	Field Inspector	Anthony Rivera
12433BV	12447BV	40	78	394	3975	4	Pioneer 4kV	6/18/2021	0.75	7/8/2021	Field Inspector	Anthony Rivera
12433BV	12447BV	40	78	394	3975	3	Shay 34kV	6/18/2021	0.75	7/8/2021	Field Inspector	Anthony Rivera
12433BV	12637BV	40	26	394	1865	4	Pioneer 4kV	7/2/2021	0.35	7/19/2021	Field Inspector	Anthony Rivera
12433BV	12637BV	40	26	394	1865	3	Shay 34kV	7/2/2021	0.35	7/19/2021	Field Inspector	Anthony Rivera
12426bv	11232bv	48	52	1/0	663	2	Pioneer 4kV	7/9/2021	0.13	7/19/2021	Field Inspector	Anthony Rivera
12445bv	1211696ctc	85	87	1/0	110	2	Pioneer 4kV	7/9/2021	0.02	7/19/2021	Field Inspector	Anthony Rivera
14763BV	9285BV / 14815BV	1	23/24	394	2726	4	Pioneer 4kV	7/15/2021	0.52	7/19/2021	Field Inspector	Anthony Rivera
14763BV	9285BV / 14815BV	1	23/24	394	2726	3	Shay 34kV	7/15/2021	0.52	7/19/2021	Field Inspector	Anthony Rivera
9774BV	12557BV	5	23	394	2182	4	Sunset 4kV	9/24/2021	0.41	10/1/2021	Field Inspector	Anthony Rivera
9774BV	12557BV	5	23	394	2182	3	Shay 34kV	9/24/2021	0.41	10/1/2021	Field Inspector	Anthony Rivera
12557BV	11095BV / 14776BV	5	34/35	394	1850	3	Shay 34kV	10/8/2021	0.35	10/22/2021	Field Inspector	Anthony Rivera
12557BV	11095BV / 14776BV	5	34/35	394	1850	4	Sunset 4kV	10/8/2021	0.35	10/22/2021	Field Inspector	Anthony Rivera
9772BV / 14765BV	9774BV	3-4	5	394	180	3	Shay 34kV	10/22/2021	0.03	10/22/2021	Field Inspector	Anthony Rivera
9772BV / 14765BV	9774BV	3-4	5	394	180	4	Sunset 4kV	10/22/2021	0.03	10/22/2021	Field Inspector	Anthony Rivera
11095BV / 14776BV	13864BV	34-35		394	60	4	Sunset 4kV	10/22/2021	0.01	10/22/2021	Field Inspector	Anthony Rivera
11095BV / 14776BV	13864BV	34-35		394	60	3	Shay 34kV	10/22/2021	0.01	10/22/2021	Field Inspector	Anthony Rivera

Start Pole #	End Pole #	Start STA #	End STA #	New Wire Size	Total Circuit Length	Conductor Qty	Circuit	Install Date	CM	BVES QC Date	BVES Inspector	BVES QC Personnel
10543BV	14829BV	23	96/97	394	3770	4	Shay 34kV	10/22/2021	0.71	10/29/2021	Field Inspector	Anthony Rivera
10543BV	14829BV	23	96/97	394	3770	3	Sunset 4kV	10/22/2021	0.71	10/29/2021	Field Inspector	Anthony Rivera
14795BV	14803BV	42	59	394	1175	4	Sunset 4kV	10/28/2021	0.22	11/12/2021	Field Inspector	Anthony Rivera
BV10985	14843BV	25	27	394	199	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14843BV	14834BV	27	29	394	199	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14834BV	14832BV	29	31	394	151	4	Paradise 4kV	11/16/2021	0.03	11/24/2021	Field Inspector	Anthony Rivera
14832BV	9044BV	31	3	394	227	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14839BV	BV10985	24	25	394	59	4	Paradise 4kV	11/23/2021	0.01	11/24/2021	Field Inspector	Anthony Rivera

Current plans for next year include applying any lessons learned and gathered throughout the year and further implementing BVES's QA/QC program for asset inspection.

BVES will continue to implement its formal manual, which was issued in December 2021.

BVES has budgeted (OPEX) $20,400 in 2022, $21,000 in 2023, and $21,600 in 2024. The RSE value for this initiative is 28.6.

Future improvements to initiative

BVES will monitor the results of its asset management QA/QC programs and implement improvements as warranted. BVES will also exchange information with other utilities to determine best practices in asset management QA/QC for consideration in BVES's program. Furthermore, BVES is in the process of implementing asset management inspection software, which will enhance the ability to document QC activities and perform QA on asset management inspections.

7.3.4.15 Substation inspections

This initiative covers the **Substation Inspection Program**.

***Risk to be mitigated** / problem to be addressed*

This initiative aligns with requirements under GO 174 for inspections of substations by qualified personnel to determine needs for upgrades, replacements, or repairs, and to maintain structural integrity of the asset to prevent ignition risks from equipment failures.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
Substation transformer and other equipment inspections are mandated by the CPUC through GO 174 facilities inspections. Substation inspections provide both reliability and incidental wildfire mitigation benefits. Substation inspections mitigate the risk of equipment failures which have the potential to cause wildfire ignitions. The inspections also provide benefits when a substation is in the HFTD or wildland urban interface. Gas in oil analysis is performed every year. If gas is detected in the oil, a cause analysis is performed to determine if the transformer can be repaired or requires replacement. Other inspections such as oil levels, temperature, and contamination are also performed. These inspections will determine when a transformer is nearing its end of life so it can be scheduled for replacement.

Substation protective relay inspections are mandated by the CPUC through GO 174 facilities inspections. Protective relays are used extensively across the power system to remove any element from service that suffers a short circuit, starts to operate abnormally, or poses a risk to the operation of the system. It is essential to inspect and test substation protective relays at chosen intervals. The frequency of maintenance inspections and tests depends on the quality of the equipment, importance of the supply, and upon the conditions at the site where the relays are installed. Protective substation relays are inspected, tested, and calibrated on a periodic basis to assure proper operation. Presently, the periodic inspection for relays is every four years. If proper operation cannot be assured, for instance due to obsolescence, the relay is scheduled for replacement.

Alternatives
No comparable alternative exists. Substation inspections are mandated by GO 174 facilities inspections. These inspections are completed throughout the BVES service territory. BVES tracks conditions found during the detailed inspections and evaluates the types and quantity of conditions in order to identify

trends and remedial actions. Additionally, Protective Substation Relay Inspections are mandated by GO 174 facilities inspections. These inspections are completed in Tier 2 and 3 throughout the BVES service territory. BVES tracks conditions found during the detailed inspections and evaluates the types and quantity of conditions to identify trends and remedial actions.

Region prioritization *("where" to engage activity)*

BVES does not have any substations in the HFTD 3. BVES performs these maintenance actions on all of its substations, all of which are in Tier 2, based on cycles but the schedule can be adjusted based on need or relative risk. ***Progress on initiative***

BVES will continue with ongoing maintenance activities and schedules in 2022. BVES inspects each of its 13 substations on a monthly basis per GO-174. When a substation is removed from service for long-term maintenance (de-energized), periodic inspections may be suspended if deemed appropriate by Field Operations Supervisor.

Additionally, BVES perform thorough equipment testing on three substations per year. These tests are extensive and require the substation to be removed or partially removed from operations.

BVES spent $100,810 (OPEX) on this initiative in 2021.

BVES will continue ongoing maintenance activities and schedules in 2022. Projected spend (OPEX) in 2022 is $228,800, $235,700 in 2023, and $242,800 in 2024. The RSE value for this initiative is 2.55.

Future improvements to initiative

As each substation becomes connected to BVES's fiber network, security cameras will be installed. While these cameras will not replace actual site visual inspections for substation equipment, the cameras will serve be a useful tool to supplement site visits by checking for any obvious abnormalities. Additionally, in 2023, BVES expects to implement an asset management software application to document its substation equipment, condition, and maintenance activities.

7.3.5 Vegetation Management and Inspections

This section is revised to address RN-BVES-22-05: BVES claims aspects of its vegetation management program are "enhanced" despite meeting only minimum regulatory requirements

The following table provides detail regarding how Bear Valley's vegetation management program are enhanced beyond the GO 95 minimum requirements. It is important to note that the internal name of BVES vegetation management program is **"Enhanced Vegetation Management Program"** with references to the specific aspects of the program that go beyond the elements specifically required by CPUC General Orders. To better align with Energy Safety, BVES will be more precise in applying the modifier "enhanced" from its internal program name.

Table 7.3-5: Comparison of BVES VM Program to GO 95

Comparison of Bear Valley's Vegetation Standards to GO 95 Minimum Requirements	
Bear Valley Requirement In Excess of GO 95	**GO 95/GO 165 Requirements**
Minimum radial clearance of 72 inches between high voltage bare conductors and vegetation. (Bear Valley's bare conductors operate between 2.4kV and 72kV.)	GO 95: Minimum radial clearance of 48 inches.

No vertical coverage is allowed above sub-transmission lines (34.5kV).	GO 95: Minimum radial clearance of 48 inches.
Tree Trunk and Major Limb Exception: At the primary conductor level, mature tree trunks greater than 12 inches in diameter and major limbs greater than 12 inches in diameter with sufficient strength and rigidity may encroach within the minimum safe distance (72-inches) but not within 12 inches of the bare line conductors. The rigidity of the tree trunk or major limb must be such that it would be impossible for it to encroach within 12 inches of the bare conductor at any time during high wind, heavy icing and snow, or other conditions. Must satisfy Tree Trunk and Major Limb Exception flowchart in Bear Valley's Vegetation Management and Vegetation QA/QC Programs.	GO 95: Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions.
All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.	GO 95: Minimum radial clearance of 48 inches.
Dead, rotten, or diseased trees or dead, rotten, or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of power lines, said trees or portions thereof must be removed. Note that this may apply to trees outside the clearance zone.	GO 95: Minimum radial clearance of 48 inches.
BVES conducts two patrol inspections per year. One is conducted by BVES's qualified Field Inspector. The other is conducted by a qualified contractor experience in power line inspections and is referred to as "Third Party Ground Patrol" (Initiatives 7.3.5.9 and 7.3.5.11)."	GO-165: Patrol inspections in rural areas shall be increased to once per year in Tier 2 and Tier 3 of the High Fire-Threat District.
BVES conducts one LiDAR survey per year of its entire overhead system. (Initiative 7.3.5.7)	GO 95/GO 165: No LiDAR inspection requirement in GO 95 or GO 165.
BVES conducts one aerial HD photography/videography survey per year of its entire overhead system. (Initiative 7.3.5.9)	GO 95/GO 165: No LiDAR inspection requirement in GO 95 or GO 165.

Since implementing its specifications contained in its Enhanced Vegetation Management Program in April 2018, BVES has seen a drop in vegetation contacting wire events. From 2001-2018 BVES averaged 13.45 wire contact events annually, and from 2019-2021 that number reduced to an average of 5.33 contact events.

7.3.5.1 Additional efforts to manage community and environmental impacts

This initiative covers the **Contracted Forester Service // Environmental Impact Mitigation Activities**.

***Risk to be mitigated** / problem to be addressed*

This initiative presents a strategy to mitigate negative impacts from utility vegetation management to local communities and the environment, which includes coordination plans with community partners and lands management groups. The work associated with this initiative serves to maintain the surrounding forested land with environmental and ecosystem caution while reducing the potential of wildfire ignition.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Utility vegetation management is one of the most impactful wildfire mitigation efforts; therefore, it is vitally important that it be conducted in a manner that minimizes any negative impacts on the local community and the environment. Such negative impacts, if not handled properly, could eventually create resistance in the local community and stakeholders to vegetation clearance efforts around bare power lines. Therefore, it is imperative to have an effective public engagement that is coordinated with local government, agencies, other utilities, and community stakeholders in its vegetation management strategy.

Alternatives
There is no alternative to engaging the community, local government, agencies, other utilities, and community stakeholders on this initiative. Failure to conduct an effective strategy to manage community and environmental impacts of vegetation management would likely result in poor vegetation management outcomes.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles) and the number of customers is relatively small (approximately 24,600). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform vegetation clearance activities on all circuits to maintain minimum clearances established in GO 95. Furthermore, because BVES has higher minimum clearance standards community buy-in is essential. Due to the small service area and customer base, BVES is able to effectively engage the entire community. Additionally, BVES targets engagement with customers living in the "high risk areas" that BVES has identified. BVES works with certain stakeholders on a priority basis due to the significant impact that they have in achieving community buy-in. These stakeholders are the Big Bear Fire Department, CAL FIRE, City of Big Bear Lake, San Bernardino County, and USFS.

Progress on initiative

Due to the already proactive nature of fuels management within the Big Bear Valley community, BVES is not contemplating developing a specific fuels management program or joint roadmap with the USFS or other land management agencies. However, BVES will join these already effective programs and provide support as needed. BVES will continue outreach, support, and participate in community-based fuels management and defensible space programs and establish communications with the USFS to determine interest in working cooperatively on fuels reduction and defensible space efforts. BVES will look to develop collaborative efforts in 2022 as noted above.

BVES has supported Fuels Management and Defensible Space Community Programs to enable more collaborative activities within the mountainous service area and to bolster existing fuels management activities.

Big Bear Valley has been a proactive community in developing and participating in fuels management and defensible space programs. Since the initial 2005 Big Bear Valley Community Wildfire Protection Plan (CWPP), various wildfire prevention strategies that were identified at that time have been implemented and completed. Since the initial CWPP, significant progress has been made through an ongoing and well-coordinated effort between various local, state, and federal agencies to reduce hazardous fuels across the valley through a wide range of fuel reduction projects. In the 2018 version of the CWPP, Big Bear Valley reports that $5,107,530 in grants has been received by the Big Bear Valley Fire Department. The Big Bear Fire Department has implemented a hazardous tree removal program which focuses on the removal of those dead trees which pose the greatest threat to habitable structures, roadways, and infrastructure. Community outreach is also an essential part of this program for acceptance and success within the community. BVES works closely with the Big Bear Fire Department and supports their grant efforts in this area.

Last year, Bear Valley Community Services District (CSD) applied for a CAL FIRE grant to address the wildfire hazard on the north/northwestern border of Bear Valley Springs, where over 85 percent of the conifer forest is dead. A $1,026,144 project will take place between August 2020 and March 2024, where a professional logging company will fall, limb, buck, and remove trees and treat slash.

Since 2006, the Big Bear Fire Department applied for, and received, grant funding to establish a curbside chipping program. The Annual Curbside Chipping Program encourages homeowners to thin or remove hazardous fuels from their property in accordance with established defensible space guidelines and place the vegetation at the curbside.

In 2019, 2020, and 2021, BVES community briefs on wildfire mitigation included discussion on BVES's enhanced vegetation efforts, treatment of at-risk species, and removal of hazard trees.

BVES will continue conduct outreach with the USFS, CAL FIRE and Big Bear Fire Department in an effort to develop collaborative measures in the area of fuels management in 2022. BVES will be supporting the establishment of the Big Bear Fire Safe Council to help educate the community in wildfire prevention activities that the community can be involved it to increase wildfire risk awareness and step that the community can take of support to mitigate the threat of wildfire.

BVES spent $35,822.02 (OPEX) in 2021 relating to work performed across HFTD Tier 2 and Tier 3 vegetation management activities with a projected spend of $38,400 in 2022 (OPEX), $39,500 in 2023, and $40,700 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES will work to establish more frequent and regular communications and coordination with the USFS to determine future interest in collaborative fuels management work such as enhanced clearances or species treatment activities. Additionally, BVES is working through its support of Big Bear Fire Safe to increase support in the community for fuels management including clearance around utility power lines.

BVES will also exchange information with other utilities to determine best practices in this area of managing community and environmental impacts on the vegetation management program.

7.3.5.2 Detailed inspections of vegetation around distribution electric lines and equipment

This initiative covers the **Enhanced Vegetation Management Program // Detailed Inspections**.

Risk to be mitigated */ problem to be addressed*

This initiative aligns with GO 165, which requires utilities to execute careful, visual inspections of overhead electric distribution lines and equipment along rights-of-way. In these Detailed Inspections vegetation and individual trees in the rights-of-way are carefully examined, visually, and discrepancies are recorded. This inspection is thorough and is more time consuming than Patrol Inspections. Individual pieces of equipment and structures are carefully examined to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying vegetation encroachments to minimum clearance requirements (as established by GO-95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

Initiative selection *("why" engage in activity)*

"why" engage in activity
In compliance with GO 165, BVES's Inspection Program requires overhead facilities to be patrol inspected each year. A "detailed inspection" is a more careful visual exam of individual pieces of equipment. The inspector records the results of the visual examinations and rates the condition of the vegetation. These inspections are designed to identify any vegetation encroachment inside of BVES's minimum clearance standards or encroachment that will lead to violation of minimum clearance standards before the next scheduled vegetation clearance crew visit. These encroachments have the potential to spark and ignite a wildfire. Detailed Inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities. BVES conducts these inspections at least once every five years in compliance with GO 165 and GO 95 (Rule 18). If any defects outlined above are identified, BVES prioritizes the defect resolution based on risk and resolves the issues in compliance with GO 95 Rule 18 timeframes. BVES divides its system up and each year conducts a number of Detailed Inspections such that each circuit is Detailed Inspected at least every five years. BVES's Field Inspector performs the Detailed Inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines. The Field Inspector works closely with the contracted Forester to ensure he is equipped to properly inspect vegetation around power lines.

Detailed Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of Detailed Inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
The Detailed Inspections are a compliance activity required by GO 165 and must be performed. Detailed Inspections provide BVES with additional information on the electric distribution equipment and provide the ability to take corrective actions prior to an event that could cause a potential ignition.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES is required to perform a Detailed Inspection of all of its circuits every five years per GO 165. BVES divides this up into a five-year schedule that achieves the GO 165 requirement. On average, it takes the Field Inspector approximately 40 full workdays to conduct the annual portion of the Detailed Inspections of BVES's overhead facilities and power lines (not including documenting findings in the database). Therefore, not much risk reduction is gained by prioritizing higher risk areas over lower risk areas.

Progress on initiative

In 2022 BVES's target is to conduct 29 circuit miles of Detailed Inspections of the sub-transmission and distribution system per BVES's five-year Detailed Inspection program as required by GO 165. Additionally, BVES will be implementing a new inspection application with mobile device data acquisition. The BVES Field Inspector is working closely with the software developers to ensure the software is customized to BVES's requirements which include compliance with GO 95 and GO 165.

BVES spent $8,177.86 (OPEX) in 2020 covering Tier 2 and Tier 3 HFTDs. BVES achieved 100 percent of planned detailed inspections in 2021. BVES has budgeted $8,400 in 2022, $8,700 in 2023, and $8,900 in 2024. The RSE value for this initiative is 34.7.

Future improvements to initiative

BVES will continue to cross check the effectiveness of its Detailed Inspections by validating the results with other vegetation inspections (Patrol Inspections, LiDAR, UAV Imagery, 3rd Party Ground Patrol Inspections, etc.) to improve its detailed inspection techniques. BVES will also exchange information with other utilities to determine best practices in vegetation detailed inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of detailed inspection results to determine if systemic issues are impacting BVES's system with respect to vegetation clearance compliance.

7.3.5.3 Detailed inspections of vegetation around transmission electric lines and equipment

This is not an applicable initiative.

***Risk to be mitigated** / problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

***Region prioritization** ("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.5.4 Emergency response vegetation management due to red flag warning or other urgent conditions

This initiative covers the **Resource Sufficiency // High Risk Conditions Procedures** activities.

***Risk to be mitigated** / problem to be addressed*

This initiative addresses plans and execution of vegetation management activities, such as trimming or removal, executed based upon and in advance of forecast weather conditions that indicate high fire threat in terms of ignition probability and wildfire consequence.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
Vegetation around electric distribution lines and equipment poses potential risks for safety, compliance, reliability, and wildfire ignitions. To address these risks and establish mitigation programs, BVES executes robust and detailed vegetation management and inspection initiatives according to detailed specifications, scope, and schedules. BVES has developed detailed work plans, which facilitates compliance and tracking adherence to CPUC rules as well as state and federal laws. This detailed schedule-based approach allows for proper documentation and auditing of vegetation management and inspection programs. Special attention is given to BVES high threat areas, which have both high vegetation or fuels density and high winds. BVES tracks conditions found during the detailed inspections and evaluates the types and quantity of conditions in order to identify trends and remedial actions.

The utility created the vegetation management plan with wildfire prevention in mind, collaborating with the City of Big Bear Lake, local Fire Departments, and the USFS.[51] The plan will be reviewed and updated on an as-needed basis not to exceed three years, depending on changing conditions.

Alternatives
There is no effective alternative at this time to conducting emergency response vegetation management. Bare conductor contact with vegetation has a significant probability of occurrence, which may then result in ignitions and wildfire. Therefore, vegetation management and inspection initiatives must be completed throughout the BVES service area to mitigate the threat of wildfire.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. Special attention is given to BVES identified high threat areas (in both HFTD Tier 3 and 2), which have both high vegetation or fuels density and high winds.

Progress on initiative

When high fire threat weather is forecasted, BVES will consult with its vegetation contractor to ensure slash from work in progress is removed; to determine if there is any work in progress or planned that should be suspended due to the risk of causing an ignition in the process of conducting the work; and to

[51] BVES has met with these stakeholders in the previous year to gather feedback and input on its vegetation maintenance program, emergency planning, and wildfire mitigation strategy.

determine if that is any short-term work that should be completed before the high fire threat weather occurs (such as, completing a tree removal that was already in progress, etc.).

The Wildfire Mitigation and Reliability Engineer and the Forester have weekly meetings with the vegetation management contractor to review planned work, status of work completed or in progress, and upcoming issues such as high fire threat weather.

BVES spent $117,630.09 (OPEX) in 2021 relating to work performed in this area across HFTD Tier 2 and Tier 3 vegetation management activities. This proportion of spend covers portions of the tree trimming contracting crew support and additional third-party resources. This activity also provides ongoing efforts for emergency response vegetation management due to RFWs or other urgent weather conditions.

BVES will continue with existing mandated and additional initiatives under the vegetation management program.

In 2022, BVES projects a budget (OPEX) of $97,300, $100,200 in 2023, and $103,200 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES will also exchange information with other utilities to determine best practices in emergency response vegetation management due to red flag warning or other urgent conditions for consideration in BVES's vegetation clearance program.

7.3.5.5 Fuel management (including all wood management) and reduction of "slash" from vegetation management activities

This initiative covers the **Enhanced Vegetation Management Program // Fuels Mitigation Activities**.

***Risk to be mitigated** / problem to be addressed*

This initiative involves fuel management (including all wood management) and management of "slash" from vegetation management activities. It targets planning and execution of fuel management activities that reduce the availability of fuel in proximity to potential sources of ignition, including both reduction or adjustment of live fuel (in terms of species or otherwise) and of dead fuel, including "slash" from vegetation management activities that produce vegetation material such as branch trimmings and felled trees.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES routinely engages in fuels removal activities within the right-of-way to maintain forest health and target overgrown and scattered vegetation that potentially threaten to encroach within vegetation clearance specifications during vegetation management inspections.

Fuels reduction is a key element to wildfire mitigation. BVES's vegetation clearance contractor clears vegetation and removes all vegetation waste and slash from the area. If the property owner wants the vegetation waste (for firewood, chipping, etc.), the contractor will assist the property owner in removing the vegetation waste from the rights-of-way for their use. BVES collaborates with the US Forest Service to remove trees near lines and removes the slash as agreed upon by the local US Forest Ranger.

Alternatives
There are no applicable alternatives to consider at this time. Vegetation waste from clearance activities must be removed from the right-of-way as well as slash that is within or near the right-of way.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES is required to conduct vegetation clearance including fuel management and removal of fuels along its power lines by GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections. Fuel management in the right-of-way in high-risk areas are prioritized for removal as they are identified.

Progress on initiative

BVES established conditions with its vegetation contractor requiring the contractor to remove all slash as it progresses along the vegetation clearance cycle schedule and as it clears areas in response to inspection findings. In 2022, BVES will continue to have all slash removed from the rights-of-way that it clears. Additionally, BVES will work to improve its collaboration with the USFS to remove slash from the areas around the power lines and how BVES may support some of the USFS efforts to reduce fuel in USFS-owned areas.

In compliance with Public Resource Code 4293 BVES cleared 10,493 poles in 2021

BVES spent $141,310.90 (OPEX) in 2021 relating to removal of slash across HFTD Tier 2 and Tier 3 vegetation management activities. Projected spend (OPEX) in 2022 is $115,000, $118,500 in 2023, and $122,000 in 2024. The RSE value for this initiative is 5.07.

Future improvements to initiative

BVES will exchange information with other utilities to determine best practices in slash removal activities for consideration in BVES's vegetation clearance program.

7.3.5.6 Improvement of inspections

This initiative covers the **VM Inspection Improvement Activities**.

Risk to be mitigated */ problem to be addressed*

This initiative includes identifying and addressing deficiencies in inspections protocols, practices, and implementation by improving training and the evaluation of inspectors the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This initiative supports improvement of training and applying lessons learned from third party contractor services and inspections. This initiative includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This will support improvement of work outcomes, training of personnel involved in vegetation management, and applying lessons learned from internal and external evaluations and audits.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES maintains routine training and assessment of vegetation management practices. BVES also applies annual lessons learned or identified improvements and tracks developing inspection practices in the industry. BVES conducts quarterly vegetation management assessments, and an annual audit of the vegetation management programs to identify and develop areas for improvements.

Alternatives
There are no alternatives to this activity apart from meeting current GOs and utility inspection standards.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES performs inspection improvement activities across all of its inspections. Inspection techniques for the various inspections BVES performs do not vary significantly. Therefore, not much risk reduction is gained by prioritizing improvement of inspections in higher risk areas over lower risk areas – the same inspections are performed across the service territory.

BVES does prioritize implementing lessons learned and inspection improvements in its high-risk areas and prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES aims to improve vegetation management inspection by conducting QA assessments and audits per BVES QA/QC procedures (provided in Appendix E). In 2022, BVES set a target to conduct four quarterly QA assessments, and one annual program audit. Quarterly audits will be conducted by the Wildfire Mitigation and Reliability Engineer, and the annual program audit by the contracted Forester.

The quarterly QA assessments include the following:

- Brief narrative on the status of the VM program, VM QC checks program and analysis or commentary on the metrics below as applicable.
- Number of trees trimmed as a result of the vegetation management program.
- Number of trees removed as a result of the vegetation management program.
- Number of Level 1 vegetation discrepancies identified.
- Number of Level 1 vegetation discrepancies resolved.
- Number of Vegetation Orders issued.
- Number of Vegetation Orders resolved.
- Any accidents, incidents, or near misses on the part of vegetation clearance personnel.
- Number of outages where vegetation made contact with power lines and caused the outage (break out those outages where vegetation clearance was in violation of standards)
- List of VM QC Checks performed (includes name of evaluator and date performed)
- List of significant findings from VM QC checks.
- Service area map showing where contractor worked in the quarter and where contractor will work in the next quarter.
- Where the contractor is in the vegetation cycle plan (e.g., percent complete).
- Corrective action taken on issues noted in previous Quarterly VM Program Assessments.
- Other items that would be useful to Management regarding vegetation management

An annual QA audit is conducted by the Forester in January each year covering the previous calendar year. The audit provides a comprehensive review of the VM Program covering at a minimum the areas and questions specified in the table below, VM Program Annual QA Audit Areas.

Table 7.3-6: VM Program Annual QA Audit Areas

VM Program Annual QA Audit Areas	
VM Line Clearance	Is the VM program effective at ensuring vegetation meets required clearance specifications?
	Is the VM program on track with the program schedule?
	Is the VM program effective in reducing vegetation contact with bare conductors?
	Are any changes to the VM clearance standards delineated in Section 3 necessary?
	Is the VM clearance contractor(s) executing work in accordance with the VM contract(s)?
	Are changes to the VM Contract Scope of Work needed?
VM Inspections	Are VM inspections (patrol, detailed, LiDAR, etc.) conducted in accordance with the Company's effective Wildfire Mitigation Plan?
	Are the results of VM inspections documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
	For each type of inspection performed, assess whether the inspection is effective and useful to assisting in achieving VM program objectives?
	Should additional inspections be performed?
	Is the scheduling of inspections appropriate or should the schedule be modified?
VM QC Checks	Are VM QC checks performed in accordance with the requirements of this policy and procedure (Section 5.3)?
	Are personnel performing VM QC checks sufficiently knowledgeable and qualified to perform the checks?

	Are VM QC checks documented?
	Are discrepancies identified in VM QC checks being tracked and resolved in a timely manner in accordance with GO-95 Rule 18?
	Are VM QC checks effective at identifying vegetation clearance issues?
	Should modifications to Appendix B VM QC Check Instructions be made?
VM Quarterly Reports	Are the VM Quarterly Reports conducted per Section 4.1.24?
	Are the VM Quarterly Reports useful in providing management an assessment of the VM program?
	Should changes be made to the content or periodicity of the VM Quarterly Reports?
VM Program	Overall, are the Company’s VM Program objectives achieved?
	Are changes recommended to the VM Program Policy and Procedures?
	Are changes in the Company’s execution of its VM Program warranted?

BVES spent $56,023.71 (OPEX) in 2021 covering improvements to inspection practices performed throughout the year within HFTD Tier 2 and Tier 3. BVES budgets (OPEX) $60,200 in 2022, $62,000 in 2023, and $63,900 in 2024. The RSE value for this initiative is 0.73.

As discussed above, in 2021, BVES added a QA program component to the Vegetation Management QC program (Appendix E).

Additionally, BVES will be implementing a new inspection application and will work to ensure the new software GIS database application meets BVES compliance requirements in the area of vegetation management. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES’s requirements.

Future improvements to initiative

BVES will exchange information with other utilities to determine best practices in inspection improvement activities for consideration in BVES’s vegetation inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES’s system with respect to vegetation clearance compliance.

7.3.5.7 Remote sensing inspections of vegetation around distribution electric lines and equipment

This initiative covers the **LiDAR Inspection Program**.

***Risk to be mitigated** / problem to be addressed*

This initiative involves conducting inspections of right-of-way using LiDAR remote sensing methods. This relatively quick and accurate inspection will allow BVES to verify, document and resolve vegetation encroachment and overheating and degrading equipment issues before they make contact with bare conductors.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES conducts one LiDAR sweep per year to evaluate the effectiveness of clearance efforts and identify potential wildfire hazards. This is an enhanced inspection using LiDAR (Light Detection and Ranging) inspections and analysis, which uses a system of lasers and software to develop surveys of the overhead sub-transmission and distribution systems, to accurately determine vegetation clearances to conductors. BVES began using LiDAR through a pilot project initiative using both helicopter and fixed wing flights, as well as via a truck-mounted mobile system. Given the proximity of the majority of BVES's electrical system to the road network and the tree canopy that is typical of distribution systems, truck-mounted mobile LiDAR will be utilized more often because it is more effective.

LiDAR survey findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action. When BVES received the LiDAR survey report, each finding is investigated by qualified personnel in evaluating vegetation clearances around power lines to validate the actual conditions and reassign the priority per GO 95, if deemed appropriate. The LiDAR contractor will immediately inform BVES of any level 1 findings so that they may be corrected or resolved to a level 2 or 3 finding as soon as possible.

The Wildfire Mitigation and Reliability Engineer reviews the results of LiDAR surveys and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the result of LiDAR surveys as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of LiDAR surveys are validated against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
No comparable alternative exists. The LiDAR pilot was able to detect potential wildfire ignition hazards source such as broken limbs near conductors and improper clearance and is considered a success at mitigating potential ignition sources. Additionally, LiDAR use at other utilities over the past years as demonstrated the significant value of this inspection technique. Consequently, BVES will continue to perform one LIDAR inspection per year as an on-going program.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES performs a LiDAR survey of all circuits each year. It takes its expert contractor approximately two weeks to gather LiDAR data on the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much risk reduction could be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the LiDAR inspection prior to the fire season Santa Ana wind period

Progress on initiative

In 2022, BVES's target is to conduct a LiDAR survey of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. Additionally, BVES will be implementing a new inspection application and will work on how to merge LiDAR data files into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES's requirements to include LiDAR survey results. BVES is also providing its risk map modeling consultant, Technosylva, with its LiDAR survey results so that BVES's service area may be accurately modeled for the risk of ignitions and wildfire spread.

BVES spent $59,560.00 (OPEX) in 2021 with a contracted vendor covering the service area over HFTD Tier 2 and Tier 3. Projected spend in 2022 is $65,000 in 2022, $66,500 in 2023, and $68,500 in 2024. The RSE value for this initiative is 4.91.

BVES will continue with an annual inspection in 2022 and apply any lessons learned.

Future improvements to initiative

BVES will evaluate combining LiDAR efforts with UAV HD imagery and thermography efforts. BVES will continue to monitor the effectiveness of the truck-mounted mobile system for the LiDAR inspection program.

BVES will continue to cross check the effectiveness of its LiDAR surveys by validating the results with other vegetation inspections (Detailed Inspections, Patrol Inspections, UAV Imagery, 3rd Party Ground Patrol Inspections, etc.) to improve LiDAR survey techniques. BVES will also exchange information with other utilities to determine best practices in vegetation LiDAR survey techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to vegetation clearance compliance.

7.3.5.8 Remote sensing inspections of vegetation around transmission electric lines and equipment

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.5.9 Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations

This initiative covers the **Third-Party Ground Patrol** (7.3.5.9.1) and the **UAV HD Photography/Videography Inspection Program** (7.3.5.9.2).

7.3.5.9.1 Third-Party Ground Patrol

Risk to be mitigated */ problem to be addressed*

This initiative is a 3rd Party Ground Patrol inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept. The 3rd Party Ground Patrol Inspection is a second patrol inspection conducted in accordance with GO 95 and GO 165 standards by a third-party independent contractor. The 3rd Party Ground Patrol Inspection is a careful, visual inspection of overhead electric distribution lines and equipment along rights-of-way that is designed to identify obvious hazards. This includes careful examination of individual pieces of equipment and structures to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying vegetation encroachments to minimum clearance requirements (as established by GO-95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

Initiative selection *("why" engage in activity)*

"why" engage in activity
GO 165 requires overhead facilities to be patrol inspected each year. A "patrol inspection" is a visual inspection designed to identify obvious problems, gross defects, and hazards. Gross defects may include, but are not limited to, vegetation encroachment inside of minimum clearance standards, etc. These encroachments have the potential to spark and ignite a wildfire. Patrol inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities.

This inspection conducted by a contracted 3rd party satisfies GO 165 patrol inspection requirements and is in effect an additional annual GO 165 patrol inspection to the one that the BVES's Field Inspector performs as described in **section 7.3.5.11**. BVES contracts experienced and qualified electrical distribution vegetation inspection contractors to perform this ground patrol inspection.

3rd Party Ground Patrol Inspection findings are rated in accordance with GO 95 Rule 18 (Level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections, as well as other vegetation inspections, to determine if there are systemic issues that must be addressed. Finally, the results of the 3rd Party Ground Patrol Inspections are validated against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
BVES could consider forgoing this inspection beyond the compliance requirements but, at this time, BVES considers this inspection a valuable wildfire mitigation initiative. There are no other alternatives considered at this time.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES performs a 3rd Party Ground Patrol Inspection of all of its circuits each year. It takes its expert contractor approximately three weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much risk reduction is gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the 3rd Party Ground Patrol Inspection prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES's target is to conduct a 3rd Party Ground Patrol Inspection of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. Additionally, BVES will be implementing a new inspection application and will work on including the inspection findings into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES's requirements to include the inspection results.

BVES spent $15,930 in 2021 on this activity. BVES has budgeted (OPEX) $40,000 in 2022, $41,500 in 2023, and $42,700 in 2024. The RSE value for this initiative is 6.51.

Future improvements to initiative

BVES will continue to cross check the effectiveness of the 3rd Party Ground Patrol Inspections by validating the results with other vegetation inspections (Detailed Inspections, Patrol Inspections, LiDAR, UAV Imagery, etc.) to improve patrol inspection techniques. BVES will also exchange information with other utilities to determine best practices in vegetation patrol inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to vegetation clearance compliance.

7.3.5.9.2 UAV Photography/Videography Inspection Program

***Risk to be mitigated** / problem to be addressed*

This initiative is a high definition (HD) imagery aerial survey of BVES's sub-transmission and distribution facilities and power lines inspection of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept. This relatively quick and accurate inspection will allow BVES to verify, document and resolve vegetation encroachment and overheating and degrading equipment issues before they make contact with bare conductors.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
No comparable alternative exists. The UAV Imagery survey provides quick and meaningful inspection methods are not able to provide. The top-down view and the ability to zoom into facilities with high-definition imagery allows data analysists to identify and pinpoint vegetation clearance issues with high fidelity that are not necessarily visible through routine patrol inspections and detailed inspections. Obviously, the tree canopy can be an impediment, but overall, the benefit of the UAV Imagery survey is an effective element of inspection necessary to mitigate wildfire.

Alternatives
BVES could consider forgoing this inspection beyond compliance requirements but at this time BVES considers this inspection a valuable wildfire mitigation initiative that provides visibility of potential ignition hazards where other inspection methods fall short. BVES benefits from HD imaging provide granular awareness into potential failures as highlight areas of degradation. There are no applicable alternatives to the value gained from implementing this activity.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES performs a UAV HD Photography/Videography survey of all of its circuits each year. It takes an expert contractor approximately six weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). Therefore, not much could be gained by prioritizing higher risk areas over lower risk areas.

BVES does prioritize completing the UAV HD Photography/Videography Survey prior to the fire season Santa Ana wind period.

Progress on initiative

In 2022, BVES's target is to conduct a UAV HD Photography/Videography Survey of the entire sub-transmission and distribution system (211 circuit miles) before the fire season Santa Ana wind event period. This will be the second year BVES has performed this type of inspection. Additionally, BVES will be implementing a new inspection application and will work on including the inspection findings into the inspection GIS database. The Wildfire Mitigation and Reliability Engineer is working closely with the software developers to ensure the software is customized to BVES's requirements to include the inspection results.

BVES spent (OPEX) $53,377.50 in 2021 on ongoing UAV thermography inspections. The RSE value for this initiative is 3.24.

BVES will be continuing annual inspections with UAV thermography with anticipated (OPEX) spend of $59,400 in 2022, $59,400 in 2023, and $61,200 in 2024. These costs are equally spread between the electrical inspection activities, as they are performed concurrently.

Future improvements to initiative

BVES will continue to cross check the effectiveness of the UAV HD Photography/Videography Survey by validating the results with other vegetation inspections (Detailed Inspections, Patrol Inspections, LiDAR, UAV Imagery, 3rd Party Ground Patrol Inspection, etc.) to improve UAV imagery inspection techniques. BVES will also exchange information with other utilities to determine best practices in vegetation UAV imagery survey techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to vegetation clearance compliance.

7.3.5.10 Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.5.11 Patrol inspections of vegetation around distribution electric lines and equipment

This initiative covers the **Enhanced Vegetation Management Program // Patrol Inspection Procedures**.

***Risk to be mitigated** / problem to be addressed*

This initiative aligns with GO 165, which requires utilities to execute careful, visual inspections of overhead electric distribution lines and equipment along rights-of-way that is designed to identify obvious hazards. This includes individual pieces of equipment and structures that are carefully examined to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying vegetation encroachments to minimum clearance requirements (as established by GO-95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
In compliance with GO 165, BVES's Inspection Program requires overhead facilities to be patrol inspected each year. A "patrol inspection" is a visual inspection designed to identify obvious problems, gross defects, and hazards. Gross defects may include, but are not limited to, vegetation encroachment inside of minimum clearance standards, etc. These encroachments have the potential to spark and possibly ignite a wildfire. Patrol inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities. BVES's Field Inspector performs the patrol inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines. The Field Inspector works closely with the contracted Forrester to ensure he is equipped to properly inspect vegetation around power lines.

Patrol Inspection findings are rated in accordance with GO 95 Rule 18 (Level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of patrol inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

Alternatives
Patrol inspections are a compliance activity required by GO 165 and must be performed. Patrol inspections provide BVES with additional information on the electric distribution equipment and provide the ability to take corrective actions prior to an event that could cause a potential ignition.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform a patrol inspection of all of its circuits each year per GO 165. It takes the Field Inspector approximately 20 full workdays to conduct a patrol of BVES's 211 circuit miles of overhead facilities and power lines (not including documenting findings in the database). Therefore, not much risk reduction could be gained by prioritizing higher risk areas over lower risk areas. However, BVES believe there is value in conducting additional patrols (more than once per year) in high-risk area; especially when environmental conditions are more prone to wildfire risk. High risk areas are patrolled prior to the fire season.

Progress on initiative

In 2022, BVES's target is to conduct a patrol inspection of the entire sub-transmission and distribution system (211 circuit miles) as required by GO 165. Additionally, BVES will be implementing a new inspection application with mobile device data acquisition. The BVES Field Inspector is working closely with the software developers to ensure the software is customized to BVES's requirements which include compliance with GO 95 and GO 165.

BVES spent $19,081.67 (OPEX) on this initiative in 2021 and will continue with ongoing inspection schedules in 2022. BVES budgets (OPEX) $19,700 in 2022, $20,200 in 2023, and $20,900 in 2024. The RSE value for this initiative is 14.8.

Future improvements to initiative

BVES will continue to cross check the effectiveness of its patrol inspections by validating the results with other vegetation inspections (Detailed Inspections, LiDAR, UAV Imagery, 3rd Party Ground Patrol Inspections, etc.) to improve its patrol inspection techniques. BVES will also exchange information with other utilities to determine best practices in vegetation patrol inspection techniques for consideration in BVES's inspection program. Furthermore, as discussed above, BVES is in the process of implementing vegetation inspection software, which will enhance the ability to document inspection findings, assign priorities and corrective action, and track the status of resolving the findings. Additionally, BVES staff will be able to perform higher level analysis of patrol inspection results to determine if systemic issues are impacting BVES's system with respect to vegetation clearance compliance.

7.3.5.12 Patrol inspections of vegetation around transmission electric lines and equipment

This is not an applicable initiative.

Risk to be mitigated */ problem to be addressed*

BVES does not own or operate any circuits equal or greater than 65kV.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES does not own or operate any circuits equal or greater than 65kV.

Alternatives
BVES does not own or operate any circuits equal or greater than 65kV.

Region prioritization *("where" to engage activity)*

BVES does not own or operate any circuits equal or greater than 65kV.

Progress on initiative

BVES does not own or operate any circuits equal or greater than 65kV.

Future improvements to initiative

BVES does not own or operate any circuits equal or greater than 65kV.

7.3.5.13 Quality assurance / quality control of inspections

This initiative covers the **Inspection Improvement Activities // QA/QC Activities**.

***Risk to be mitigated** / problem to be addressed*

Prevent inconsistent or ineffective inspections by establishing an audit process to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This initiative includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This will support improvement of work outcomes, training of personnel involved in vegetation management, and applying lessons learned from internal and external evaluations and audits.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
Vegetation management to achieve safe clearances around bare conductors is a vitally important aspect for enhancing public safety and mitigating the threat of wildfire. Therefore, establishing a vegetation management inspection quality assurance (QA) and quality control (QC) program is a critically essential element of a successful vegetation management program that aims to assure intended contracted vegetation clearance scope of work outcomes and vegetation management continuous process improvement.

Alternatives
There are no alternatives to this initiative apart from meeting current GOs and utility inspection standards.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform vegetation management by GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. Accordingly, BVES's inspection improvement activities will impact the entirety of BVES's service area. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections.

The vegetation management QA/QC program follows the vegetation management workflow and sequence as described above. QCs are performed as the vegetation management contractor executes the cycle schedule and also in response to correction of inspection findings.

Progress on initiative

In 2022, BVES aims to continue to execute vegetation management QA/QC per its vegetation management QA/QC procedures (provided in Appendix E), which were last updated in 2021. In 2022, BVES set a QC target to conduct 72 QCs, four quarterly QA assessments, and one annual program audit. QCs are to be conducted by qualified staff designated in the BVES vegetation management procedures manual. Quarterly audits will be conducted by the Wildfire Mitigation and Reliability Engineer, and the annual program audit by the contracted Forester.

QC reviews check the quality of recent vegetation clearance activities. Staff assigned vegetation management QCs receive a GIS map that illustrates the specific trees trimmed and/or removed and the pole numbers for each pole in assigned QC area. The assigned staff then go to the assigned area and inspect the assigned area to determine whether the contractor cleared the vegetation surrounding the lines in accordance with BVES vegetation clearance specifications. The staff utilize a checklist to conduct the QC and document the results in an online application used to manage, document, and archive vegetation management QCs. Discrepancies are forwarded to the vegetation management contractor to resolve. Additionally, the vegetation management QC application collects QC finding results and allows for analysis of potential systemic issues.

The quarterly QA assessments include the following:

- Brief narrative on the status of the VM program, VM QC Checks program, and analysis or commentary on the metrics below as applicable.
- Number of trees trimmed as a result of the vegetation management program.
- Number of trees removed as a result of the vegetation management program.
- Number of Level 1 vegetation discrepancies identified.
- Number of Level 1 vegetation discrepancies resolved.
- Number of Vegetation Orders issued.
- Number of Vegetation Orders resolved.
- Any accidents, incidents, or near misses on the part of vegetation clearance personnel.
- Number of outages where vegetation made contact with power lines and caused the outage (break out those outages where vegetation clearance was in violation of standards)
- List of VM QC Checks performed (includes name of evaluator and date performed)
- List of significant findings from VM QC Checks.
- Service area map showing where contractor worked in the quarter and where contractor will work in the next quarter.
- Where the contractor is in the vegetation cycle plan (e.g., percent complete).
- Corrective action taken on issues noted in previous Quarterly VM Program Assessments.
- Other items that would be useful to Management regarding vegetation management

The annual QA audit is conducted by the Forester in January each year covering the previous calendar year. The audit is intended to be a comprehensive review of the VM Program covering at a minimum the areas and questions specified in the table below, VM Program Annual QA Audit Areas.

Table 7.3-7: VM Program Annual QA Audit Areas

VM Program Annual QA Audit Areas	
VM Line Clearance	Is the VM program effective at ensuring vegetation meets required clearance specifications?
	Is the VM program on track with the programmed schedule?
	Is the VM program effective in reducing vegetation contact with bare conductors?

	Are any changes to the VM clearance standards delineated in Section 3 necessary?
	Is the VM clearance contractor(s) executing work in accordance with the VM contract(s)?
	Are changes to the VM Contract Scope of Work needed?
VM Inspections	Are VM inspections (patrol, detailed, LiDAR, etc.) conducted in accordance with the Company's effective Wildfire Mitigation Plan?
	Are the results of VM inspections documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
	For each type of inspection performed, assess whether the inspection is effective and useful to assisting in achieving VM program objectives?
	Should additional inspections be performed?
	Is the scheduling of inspections appropriate or should the schedule be modified?
VM QC Checks	Are VM QC Checks performed in accordance with the requirements of this policy and procedure (Section 5.3)?
	Are personnel performing VM QC checks sufficiently knowledgeable and qualified to perform the checks?
	Are VM QC Checks documented?
	Are discrepancies identified in VM QC checks tracked and resolved in a timely manner in accordance with GO-95 Rule 18?
	Are VM QC Checks effective at identifying vegetation clearance issues?
	Should modifications to Appendix B VM QC Check Instructions be made?
VM Quarterly Reports	Are the VM Quarterly Reports conducted per Section 4.1.24?
	Are the VM Quarterly Reports useful in providing management an assessment of the VM program?

	Should changes be made to the content and/or periodicity of the VM Quarterly Reports?
VM Program	Overall, are the Company's VM Program objectives achieved?
	Are changes recommended to the VM Program Policy and Procedures?
	Are changes in the Company's execution of its VM Program warranted?

BVES spent $56,023.71 (OPEX) in 2021 covering improvements to inspection practices performed throughout the year within HFTD Tier 2 and Tier 3. BVES budgets (OPEX) $60,200 in 2022, $62,000 in 2023, and $63,900 in 2024. The RSE value for this initiative is 0.73.

As discussed above, in 2021, BVES added a QA program component to the Vegetation Management QC program (Appendix E).

Future improvements to initiative

BVES will monitor the results of its vegetation management QA/QC programs and implement improvements as warranted. BVES will also exchange information with other utilities to determine best practices in vegetation management QA/QC for consideration in BVES's program. Furthermore, BVES is in the process of implementing vegetation management inspection software, which will enhance the ability to document QCs and perform QA on vegetation management inspections.

7.3.5.14 Recruiting and training of vegetation management personnel

This initiative covers the **Forester Contractor Services**.

***Risk to be mitigated** / problem to be addressed*

Recruiting and training of vegetation management personnel is a challenging endeavor given the current labor market. Therefore, BVES not only works on this issue internally but also communicates frequently with its contractors to ensure they are meeting their staffing requirements to achieve the required scope of work safely.

BVES entered a contract to engage a full-time contract utility forester in its service territory as part of the BVES team. The contract forester's job duties include inspections, auditing, customer contact and issue resolution, work plan development, specialized projects, contractor safety observations, vegetation management program documentation and data analysis, and staff training. The Forester was secured in April 2021.

The Forester trains BVES staff on vegetation management specifications and inspection techniques. He works with the Field Inspector to ensure he has the right knowledge on vegetation clearance requirements (GO-95 and BVES internal requirements) to conduct patrols and detailed inspection per GO-165. Additionally, the Forester reviews the vegetation clearance contractor's crew's qualifications to ensure they are staffing the crews with qualified personnel.

BVES Field Operations works very closely with Human Capital Management (HCM) to recruit and retain staff involved in the vegetation management area. Job postings are reviewed by both Field Operations and HCM to ensure the proper skills are being sought. HCM frequently reviews pay ranges for vegetation management staff to ensure the Company's pay ranges are competitive in the market to attract and retain qualified personnel.

Initiative selection *("why" engage in activity)*

"why" engage in activity

It is critically important to public safety to ensure that the Company and its contractors have the appropriate number staff who are involved with vegetation management and that these personnel are qualified and/or certified to the appropriate level of competence. To assist in this effort, as well as many other aspects of the vegetation management program, a full-time forester resource is required for BVES to have an effective vegetation management program.

Alternatives

As a supplement, BVES routinely trains internal personnel and ensures all contracted resources retain proper certifications and licenses to perform accurate work in accordance with vegetation management requirements.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform vegetation management by GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections.

While this approach is achievable and delivering results (declining instance of vegetation contacting bare conductors, no ignitions, no wildfires, etc.), it is contingent on having the right number of qualified vegetation management staff at BVES and for the contractors. Therefore, recruiting and training are always key efforts that BVES engages in.

Progress on initiative

BVES spent $29,198.64 (OPEX) in 2021 in related activities to this initiative category.

BVES holds periodic meetings with the vegetation management contractor and ensure that they are able to provide the necessary qualified crews to achieve the required scope of work safety. BVES will work with HCM should an opening develop in a vegetation management position at BVES. This year there are no planned retirements for vegetation management staff. BVES will work with HCM to ensure compensation (direct pay and benefits) is competitive with industry standards.

BVES's Forester audits the vegetation management contractor's crew's qualifications. The Forester will also provide training to BVES staff who perform VM QCs on how to properly evaluate vegetation clearances around power lines, at-risk species, hazardous trees, and tree trunk and major branch exemptions. Additionally, the Forester will also train Line Crews how to properly trim trees, which they occasionally due in the course of their work.

Forecasted spend (OPEX) in 2022 is $31,600, $32,500 in 2023, and $33,500 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES will monitor both its own workforce and contracted workforce to determine where improvements are possible and warranted and, consequently, implement the improvements as applicable. BVES will seek external professional training for BVES staff involved in vegetation management activities. BVES will attend T&D conferences where vegetation management is a major topic so are to learn from the experiences of other utilities. Additionally, BVES's HCM has established exit interview surveys for employees leaving the company. As this database populates, BVES management will seek to learn how to better retain staff.

7.3.5.15 Identification and remediation of "at-risk species"

This initiative covers the **Enhanced Vegetation Management Program // Hazardous Tree Removal** activities.

***Risk to be mitigated** / problem to be addressed*

This initiative includes any actions taken to reduce the ignition probability and wildfire consequence attributable to at-risk vegetation species. This work may include activities such as tree trimming, brush and slash removal, and replacement of fixtures associated with ignition risk.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES will consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to at least 12 feet minimum (or more if warranted) and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

Alternatives
There are no applicable alternatives associated with this activity.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas in mountainous, frequently dry terrain. BVES is required to perform many of these activities by GOs and applicable standards, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas.

Progress on initiative

BVES spent $150,473.64 (OPEX) in 2021 covering activities in HFTD Tier 2 and Tier 3.

There are no current plans for the next year apart from routine vegetation management inspection activities. Forecasted spend in 2022 (OPEX) is $125,500, $129,300 in 2023, and $133,100 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES does not have any specific future improvements identified at this time.

7.3.5.16 Removal and remediation of trees with strike potential to electric lines and equipment

This initiative covers the **Enhanced Vegetation Management Program // Hazardous Tree Removal** activities.

***Risk to be mitigated** / problem to be addressed*

This initiative captures the associated activities and actions taken to remove or remediate trees that have a potential to fall in or make contact with electrical equipment, leading to electrical device and structure failures or ignition sources.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES performs strike potential tree removal as identified during vegetation management patrols and inspections. Typically, these types of trees receive immediate or readily available remediation or removal in order to reduce ignition risk and maintain the structural integrity of the ROW.

Alternatives
There are no applicable alternatives associated with this activity.

***Region prioritization** ("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform hazard tree removal by GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections. Hazardous trees in high-risk areas are prioritized for removal as they are identified. In most cases, when a tree is identified for removal due to being a hazard, removal is near immediate.

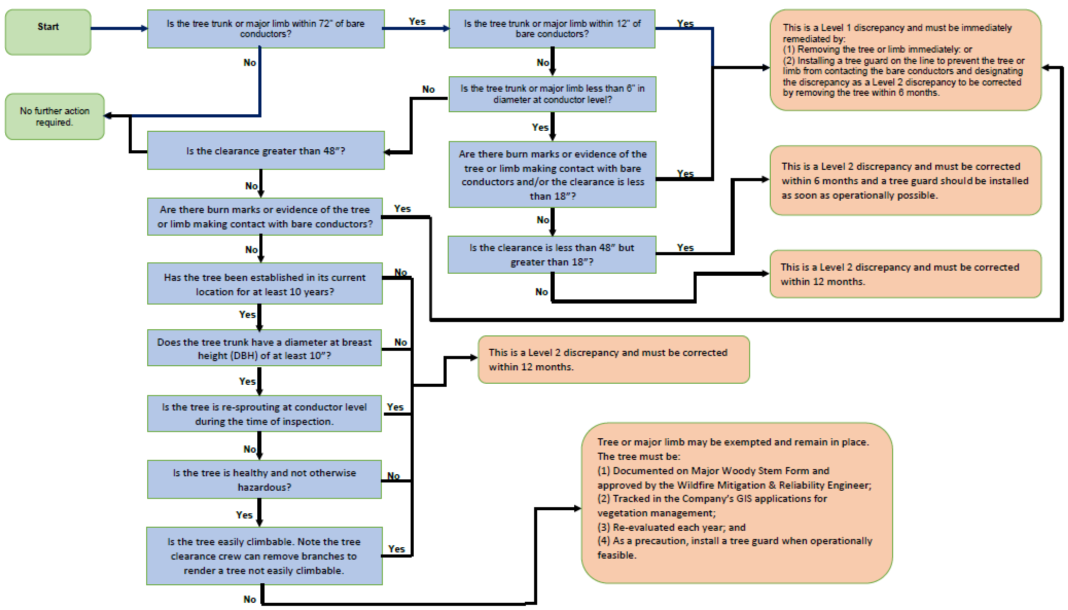
Progress on initiative

BVES spent $164,604.73 (OPEX) in 2021 covering activities in HFTD Tier 2 and Tier 3.

There are no ad hoc plans for the next year apart from routine vegetation management inspection activities. Based on past experience and past inspections, BVES expects to remove approximately 88 hazard trees along its lines. Additionally, as discussed in **Section 7.3.5.19**BVES is working to install an improved tree database. This database will document exempted trees (tree trunk exemption per GO 95) and track their condition such that if they become a hazard they may be removed.

Tree trunks and major limbs that encroach within 48 inches of bare conductors are evaluated in accordance with BVES's Trees and Major Limbs in Close Proximity to Bare Conductors flowchart below.

Figure 7.3-7: Trees and Major Limbs in Close Proximity to Bare Conductors



Trees identified as hazardous, are removed.

Anticipated spend (OPEX) in 2022 is $137,000, $141,100 in 2023, and $145,300 in 2024. The RSE value for this initiative is 0.73.

BVES spent $164,604.73 (OPEX) in 2021 covering activities in HFTD Tier 2 and Tier 3.

There are no ad hoc plans for the next year apart from routine vegetation management inspection activities. Anticipated spend (OPEX) in 2022 is $137,000, $141,100 in 2023, and $145,300 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES will continue to monitor best practices with other utilities and its vegetation contractor. Over the next three years, possibly sooner, BVES will update its exempted trees such that they are all included in the BVES's tree database described in **Section 7.3.5.19**.

7.3.5.17 Substation inspections

This initiative covers the **Substation Inspection Program**.

Risk to be mitigated */ problem to be addressed*

This initiative aligns with requirements under GO 175 for inspections of substations to determine needs for upgrades, replacements, or repairs, and to maintain structural integrity of the asset to prevent ignition risks from equipment failures. Additionally, these inspections include evaluating if vegetation growth and encroachment has occurred near substation equipment.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Vegetation overgrowth in and around substations is a potential source of ignition. Therefore, this program evaluates each substation for potential vegetation issues or non-compliance instances.

Alternatives
No comparable alternative exists. Substation inspections are mandated by GO 174 facilities inspections. These inspections are completed throughout the BVES service territory. BVES tracks conditions found during the detailed inspections and evaluates the types and quantity of conditions in order to identify trends and remedial actions.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 areas. None of BVES's 13 substations are located in the HFTD Tier 3 area. While BVES generally, BVES prioritizes high risk areas over lower risk area (note that all of BVES's area is considered extreme or elevated fire risk), because the monthly substation inspections take two days per month to conduct and all must be done per GO-174, the higher risk substations are inspected along with all of BVES's substations.

Progress on initiative

BVES has spent $5,050.66 (OPEX) on this initiative in 2021 covering HFTD Tier 2 and Tier 3 areas.

BVES will continue with ongoing maintenance activities and schedules in 2022. BVES inspects each of its 13 substations on a monthly basis per GO-174. When a substation is removed from service for long-term maintenance (de-energized), periodic inspections may be suspended if deemed appropriate by Field Operations Supervisor.

Anticipated spend (OPEX) in 2022 is $5,200, $5,400 in 2023, and $5,500 in 2024. The RSE value for this initiative is 2.55.

Future improvements to initiative

As each substation becomes connected to BVES's fiber network, security cameras will be installed. While these cameras will not replace actual site visual inspections for vegetation, the cameras will serve as a useful tool in checking for vegetation over growth. Additionally, in 2023 BVES expects to implement an asset management software application to document its substation equipment, condition, and maintenance activities.

7.3.5.18 Substation vegetation management

This initiative covers the **Substation Inspection Program // Vegetation Management**.

Risk to be mitigated */ problem to be addressed*

This initiative aligns with requirements under GO 175 for inspections of substations and involves the removal of vegetation in and around substations that may result in contact with bare conductors. The initiative is intended to reduce the likelihood of vegetation contacting bare conductor; thereby, reducing the probability of ignition. Substation vegetation clearance work is conducted in response to periodic (monthly) visual site inspection of each substation. Based on inspection results, vegetation task orders are provided to a qualified contractor.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Substation inspections are mandated by the CPUC through GO 174 facilities inspections. Vegetation issues and non-compliance instances are remediated by this program. BVES also strives to install coverings on bare conductor to reduce the impact of vegetation or animals contacting bare conductors at the substation. Additionally, where feasible, BVES has used gravel, weed barriers, and asphalt to mitigate vegetation growth in and around substations.

Alternatives
No comparable alternative exists. While most bare conductor can be eliminated from substations, vegetation encroachment must still be removed.

Region prioritization *("where" to engage activity)*

All of BVES's service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas. None of BVES's 13 substations are located in the HFTD Tier 3 area. While generally, BVES prioritizes high risk areas over lower risk area (note that all of BVES's area is considered extreme or elevated fire risk), because the actual level of effort to clear vegetation at the substations is at most one week per year, the higher risk substations are cleared along with all of BVES's substations.

Progress on initiative

BVES spent $17,340.83 (OPEX) on this initiative in 2021 covering HFTD Tier 2 and Tier 3 areas.

BVES will continue ongoing vegetation clearance activities as deemed necessary by the substation inspections in 2022. BVES look for opportunities to install weed barriers in some of its substations that do not have weed barriers.

BVES budgets (OPEX) $17,900 in 2022, $18,400 in 2023, and $18,900 in 2024. The RSE value for this initiative is 32.6.

Future improvements to initiative

7.3.5.19 BVES will continue ongoing vegetation clearance activities as deemed necessary by the substation inspections in 2022. BVES will also look for opportunities to install weed barriers in some of its substations that do not have weed barriers. Vegetation management enterprise system

This initiative covers the **Enhanced Vegetation Management Program // Inventory System Activities**.

Risk to be mitigated */ problem to be addressed*

This initiative covers the inputs, documentation, and operational support that contribute to a centralized inventory of vegetation growth, types, and clearances to achieve fuels reduction and clearance objectives. This includes the data captured surrounding at-risk and invasive species identification, growth cycle and off-cycle growth targets, vegetation fuel and forecasted load, and damaged or dying tree accounting for those that may lead to a fall in or another ignition risk driver.

This work includes practices described under BVES's Enhanced Vegetation Management Program as well as associated work executed by the contracted forester (secured in 2021).

Initiative selection ("why" engage in activity)

"why" engage in activity
BVES uses contracted services to perform the detailed vegetation management work described in **Section 7.3.5.2**. Activities recorded under this WMP initiative support routine vegetation patrols and inspection schedules. Recordkeeping practices to document ongoing activities in the field as well as general vegetation risk and growth tracking are also captured under this initiative.

Alternatives
There are no alternatives to consider for this initiative at this time. BVES has been enhancing its GIS capabilities thus supporting data collection and mapping associated with the WMP. Data tracked under this WMP initiative will have valuable future use in supporting fuel inventory mapping and lead to better forecasting of fuel loading in parallel with other resources described under **Sections 7.3.1** and **7.3.2**.

Region prioritization ("where" to engage activity)

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas in mountainous, frequently dry terrain. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

BVES is required to perform activities directed by the GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES will populate the database following its cycle schedule but will also populate it has it inspects and trims high risk areas on a priority basis.

Progress on initiative

BVES is working to install an improved tree database that creates a unique ID for each tree and holds extensive data on each tree (such as species, height, condition, etc.). The database will provide real-time vegetation inspection data available to users, trimming status, geolocation, among other things. The software will provide alerts on trees that require revisit based on growth rates. Additionally, the software will alert when a tree is about to exceed its review time based on the cycle schedule. This database will be up and running by the end of 2023.

BVES spent $206,998.00 (OPEX) in 2021in related activities to this initiative category. The contracted support will accrue costs starting in 2022.

There are no unique plans with this ongoing work. Projected spend in 2022 is $171,500, $176,600 in 2023, and $181,900 in 2024. The RSE value for this initiative is 0.73.

Future improvements to initiative

BVES expects to populate its new database over the next three years; possibly sooner. BVES is considering tagging trees with tags that electronically connect with mobile devices that crews and inspectors would use to enhance accuracy of data recording.

7.3.5.20 Vegetation management to achieve clearances around electric lines and equipment

This initiative covers the **Enhanced Vegetation Management Program // Equipment Vegetation Clearances**.

***Risk to be mitigated** / problem to be addressed*

Vegetation around electric distribution lines and equipment poses potential risks for safety, compliance, reliability, and wildfire ignitions. To address these risks and establish mitigation programs, BVES executes robust and detailed vegetation management and inspection initiatives according to detailed specifications, scope, and schedules. BVES has developed detailed work plans which enable compliance and track adherence to CPUC rules as well as state and federal laws. This detailed schedule-based approach allows for proper documentation and auditing of vegetation management and inspection programs.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity

BVES has a vegetation management plan in place that meets or exceeds the CPUC's GOs. Mowbray's Tree Service Inc., a third-party contractor, executes the vegetation clearing efforts under the direction of BVES. The contractor's work is subject to BVES Quality Control checks. The goal of this plan is to proactively maintain vegetation, so it does not come into contact with electrical infrastructure, thereby preventing wildfires. The utility created the vegetation management plan with wildfire prevention in mind, collaborating with the City of Big Bear Lake, local Fire Departments, and the USFS.[52] The plan will be reviewed and updated on an as-needed basis not to exceed three years, depending on changing conditions. The program includes three components: preventative vegetation management, corrective vegetation clearance, and emergency vegetation clearance. Each of these components needs to adhere to particular specifications, detailed below.

Preventative Vegetation Management: This scope of work encompasses ensuring vegetation on BVES overhead sub-transmission and distribution lines adheres to identified clearance specifications.

Corrective Vegetation Clearance: This scope of work consists of completing corrective and emergent vegetation orders to fix clearance discrepancies that the contractor or BVES discovers. If an order is designated as High Priority, the contractor must prioritize that work and make the correction immediately.

Emergency Vegetation Clearance: This scope of work includes completing maintenance on an as-needed basis for any major disaster or emergency events. For example, if a storm results in fallen trees and branches, the contractor must mobilize as soon as possible to clear the vegetation.
The BVES vegetation management contract contains many provisions to reduce the accumulations of brush and trees waste that may become fuel for wildfires:

The Contractor is required to remove all wood and wood products and any other wastes generated by the requested service on a daily basis.

Other requirements related to temporary slash piles, and proper disposal of wood and wood product waste according to applicable laws, rules, and regulations.

Removal of all dead and rotting trees as well as those with the potential to fall on lines, even if they are outside the required clearance zone.

As mentioned above, all vegetation management work must adhere to certain specifications, as outlined by BVES. The utility-defined specifications comply with or exceed those outlined in GO 95, Rules for Overhead Electric Line Construction, Rule 35 Vegetation management, and Appendix E Guidelines to

[52] BVES has met with these stakeholders in the previous year to gather feedback and input on its vegetation maintenance program, emergency planning, and wildfire mitigation strategy.

Rule 35 and Commission Decisions, such as D.17-12-024. As previously described BVES has unique local conditions that require it, in certain circumstances, to go beyond the regulated vegetation clearance standards. These enhanced specifications include:

Radial Clearances: Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected, taking into account vegetation species and growth rates and characteristics, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years) will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

Anytime it is determined that trimming of vegetation is necessary, BVES's contractor shall trim to least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

Blue Sky Requirement: No vertical coverage shall be allowed above BVES sub-transmission lines (34.5 kV).

Fast Growing Trees: All fast-growing trees, (e.g., poplar, aspen, cottonwood) will be trimmed to at least 12 feet and removal will be considered. BVES's contractor may determine that additional clearance would be prudent based on growth factors, wind, ice, etc.

Drip Line: All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

Tree Removal: Trees that are dead, rotten, or diseased, or dead, rotten, or diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines, should be removed. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines).

Base of Poles/Structures: For poles or structures that have non-exempt equipment per CALFIRE requirements, all flammable material and vegetation in a 10-foot radius around the base of the pole or structure shall be cut down and removed during each normal vegetation management cycle clearance visit. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.

Right of Way: All brush, limbs and foliage in the ROW shall be cut up to 8-feet above the ground. All dead, dying, diseased, or dried vegetation from 8 feet above the ground to the top of the power lines must be removed during each normal vegetation management cycle clearance visit. This requirement is applicable to all ROWs in the HFTD Tier 3 and to all ROWs in the HFTD Tier 2 designated as having high strike potential by the Wildfire Mitigation & Safety Engineer. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.

Tree Trunk and Major Limb Exception: BVES has developed a flowchart for Field Personnel to use in determining the appropriate action for trees and major limbs in close proximity to bare conductors. If there is a mature tree whose trunk or major limb is within 48 inches of bare conductors, the following action is to be taken:

> If the tree or major limb is within 12 inches of the bare conductors regardless of thickness at conductor level, this is a Level 1 discrepancy and shall be immediately remediated by:
>
> > Removing the tree or limb immediately, or
> >
> > Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.
>
> If the tree or major limb is less than 6 inches thick at conductor level, then the tree or major limb must be trimmed or removed to achieve 72 inches clearance from bare conductors as follows:
>
> > If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is greater than 48 inches, then this is a Level 2 discrepancy and shall be corrected within 12 months.
> >
> > If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is less than 48 inches but greater than 18 inches, then this is a Level 2 discrepancy and shall be corrected within 180 days. A tree guard should be installed as soon as operationally possible.
> >
> > If there are burn marks or evidence of the tree or limb making contact with bare conductors and/or the clearance is less than 18 inches, then this is a Level 1 discrepancy and shall be immediately remediated by:
> >
> > > Removing the tree or limb immediately, or
> > >
> > > Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.
>
> If the tree or major limb is greater than 6 inches thick at conductor level and greater than 12 inches from bare conductors, then the tree or major limb shall be evaluated to determine if an exemption per GO-95 Rule 35 may be applied. Take the following action:
>
> > If there are burn marks present on the tree or major limb or evidence of the tree or limb making contact with the bare conductor, this is a Level 1 discrepancy and shall be immediately remediated by:
> >
> > > Removing the tree or major limb immediately, or
> > >
> > > Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If there are no burn marks present on the tree or major limb and no evidence of the tree or limb making contact with the bare conductor, then the tree or major limb may be exempted provided the following:

Tree has been established in its current location for at least 10 years.

Tree trunk has a diameter at breast height (DBH) of at least 10”.

Tree or limb at the conductor level is at least 6” in diameter.

Tree is not re-sprouting at conductor level during the time of inspection.

Tree is healthy and not otherwise hazardous.

Tree is not easily climbable. Note the tree clearance crew can remove branches to render a tree not easily climbable.

If the tree cannot satisfy one or more of the above criteria, then the tree or major limb must be removed. It should be designated as a Level 2 discrepancy and shall be corrected within 12 months.

If the tree satisfies all of the above criteria, then the tree may be exempted and remain in place. The tree shall be:

Documented on Major Woody Stem Form and approved by the Wildfire Mitigation & Reliability Engineer.

Tracked in the Company’s GIS applications for vegetation management.

Re-evaluated each year.

As a precaution, install a tree guard when operationally feasible.

BVES will also consider the removal of any fast-growing trees, such as poplars, aspens, or cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES’s tree tracking program.

Alternatives

Vegetation management and inspection initiatives are completed throughout the BVES service territory. Special attention is given to BVES high threat areas which have both high vegetation or fuels density and high winds. BVES tracks conditions found during the detailed inspections and evaluates the types and quantity of conditions in order to identify trends and remedial actions.

Region prioritization *("where" to engage activity)*

The entire BVES service area is in HFTD Tier 2 and Tier 3 high risk wildfire service areas in mountainous, frequently dry terrain. BVES’s service area is small (32 square miles). Additionally, BVES’s HFTD Tier 3 is less that 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas.

BVES is required to perform many of these activities by GOs and applicable standards regardless of area, but BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections.

Progress on initiative

BVES's contractor has completed one entire cycle schedule of the BVES service area since beginning work with BVES. The contractor is concentrating efforts to remove hazard trees along with performing the cycle schedule. BVES has targeted to ensure 72 circuit miles are visited for vegetation clearance activities in 2022. Additionally, the vegetation contractor shall be responsible for correcting findings from the annual LiDAR survey, UAV photography/videography survey, 3rd party ground patrol, BVES patrols, BVES detailed inspections, and VM QCs.

BVES spent $2,119,663.49 (OPEX) in 2021relating to work performed across HFTD Tier 2 and Tier 3 vegetation management activities.

BVES will continue with existing mandated and additional initiatives under the vegetation management program with an estimated budget of (OPEX) $1,725,000 in 2022, $1,776,800 in 2023, and $1,830,100 in 2024. The RSE value for this initiative is 0.19.

Future improvements to initiative

BVES complies with radial clearance requirements (both GO-95 and BVES-enhanced clearance standards) by trimming trees or, if warranted, by removal of the tree. In its past practice, BVES was reluctant to remove large numbers of trees on hillsides due to concerns such as erosion, wind shear, and flooding that may arise from trimming and removing trees. However, BVES will remove single trees on hillsides. BVES will work to consult with an environmental specialist to assess large scale tree removals on hillsides and the mitigations to implement as a result. It should be noted that BVES does not have any of its main facilities on steep hillsides, and it would be rare to need to remove a large number of trees in an area.

BVES will continue to seek out best practices in vegetation management techniques. BVES leadership is performing Job Hazard Analyses (JHAs) on contractors perform vegetation management to ensure their work practices safe for the public and the employees

7.3.5.21 Vegetation management activities post-fire

This initiative covers the work associated with **Vegetation Management Activities Post-Fire**.

***Risk to be mitigated** / problem to be addressed*

This initiative aims to respond to immediate vegetation management needs related to ignition events. In many cases, there remains leftover debris from wildfires, which can post a threat to public safety. Additionally, ignitions of any size can illustrate the need to prioritize certain areas of the terrain, which may indicate further remediation based on the fire inspection and evaluation. While BVES has not experienced a significant fire, it remains prepared to respond quickly in the even an ignition source impacts adjacent vegetation or threatens public access.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
Establishing a separate initiative with procedures for post-ignition response is paramount to the four pillars of the WMP, which are to prepare, mitigate, respond, and recover. Much of the vegetation management activities are positioned as preventative means, yet do not specifically address actions undertaken after a fire has been suppressed. Since BVES's service area is surrounded by USFS lands, the utility will work with federal and state public safety partners to ensure coordination is seamless if BVES support is warranted post-event.

Alternatives
There are no alternatives considered for this initiative activity.

***Region prioritization** ("where" to engage activity)*

This initiative would address any region within the service territory following an ignition or wildfire.

Progress on initiative

BVES complies with radial clearance requirements (both GO-95 and BVES-enhanced clearance standards) by trimming trees or, if warranted, by removal of the tree. In its past practice, BVES was reluctant to remove large number of trees on hillsides due to concerns such as erosion, wind shear, and flooding that may arise from trimming and removing trees. However, BVES will remove single trees on hillsides. BVES will work to consult with environmental an specialist to assess large scale tree removals on hillsides and the mitigations to implement as a result. It should be noted that BVES does not have any of its main facilities on steep hillsides and it would be rare to need to remove a large number of trees in an area.

BVES will continue to seek out best practices in vegetation management techniques. BVES leadership is performing Job Hazard Analyses (JHAs) on contractors perform vegetation management to ensure their work practices safe for the public and the employees

Future improvements to initiative

BVES will consider example preparatory vegetation management activities performed by similar IOUs in response to a wildfire and make updates as necessary. BVES will consult with CAL FIRE, other utilities, and vegetation contractors to develop a list of preparations that would be beneficial to have in place in the event the service area experiences a wildfire.

7.3.6 Grid Operations and Protocols

Grid operations and protocols encompass company procedures related to wildfires, special work procedures, and wildfire infrastructure protection team definitions. These practices help the utility manage risk on a day-to-day basis and during wildfire high risk periods.

Understanding the electric system load/demand allows BVES to create an operating mode optimized for two types of operations: (1) safety and reliability and (2) wildfire prevention during high-risk periods. It should be noted that wildfire prevention measures during high fire risk weather conditions override reliability optimization regardless of season or system demand. Generally, since the winter months bring the heaviest load/demand on the BVES distribution system, BVES optimizes the system for safety and reliability during such time. These months are often wet and do not typically pose significant wildfire risks. Following the winter season, the operational focus becomes more defensive and optimized for wildfire prevention, given the hot, dry climate. Specifically, the system uses the following protocols:

From approximately November 1st through March 31st, the system is focused on safety and reliability with higher load settings to accommodate higher demand due to colder temperatures and reclosers set to automatic.

From approximately April 1st through October 31st, BVES adopts a more defensive operational scheme during the non-winter months. To accomplish this, the utility enacts certain operational settings:
- All fuse TripSavers are set to not reclose.
- Auto-Recloser field trip settings adjusted for summer load.
- Radford 34.5 kV line de-energized.

Although BVES generally follows a strict schedule, the utility monitors conditions, using the NFDRS, to determine if additional precautions should be taken.[53] Further, BVES staff and BVES's weather consultant review the NFDRS on a weekly basis or more frequently during high fire threat periods to make advanced preparations and on a daily basis to determine if additional steps should be taken. In short, overall system configuration is optimized for fire prevention from approximately April 1 to October 31, using the seasonal characteristics of BVES's climate and load profile. The system is then further adjusted based on the seven-day NFDRS forecast, as well as other operational and weather information available to BVES.

BVES monitors the NFDRS fire danger forecast each day and then determines the proper operational focus from a reliability and fire prevention focus. Exact steps depend on the level of fire-threat. As indicated in **Table 7.3-8** below, "Brown", "Red", and "Orange" are considered elevated fire-threat conditions that require the BVES system to be configured for fire prevention over reliability concerns.

Table 7.3-8: Operational Direction Based on NFDRS Forecast

Operational Action	Green	Yellow	Brown	Orange	Red
Circuit Recloser Settings	Automatic Reclosing	Automatic Reclosing	Non-Automatic Reclosing	Non-Automatic Reclosing	Non-Automatic Reclosing
Patrol following circuit outage	No[1]	No[1]	Yes	Yes	Yes
TripSavers	Automatic	Automatic	Non-Automatic	Non-Automatic	Non-Automatic
Proactive De-energization (PDE)	No	No	Yes – "at risk" lines when wind gusts greater than 55 mph		

[1]No patrol is required. Re-test allowed following check of fault indicators, SCADA, other system indicators, and reports from the field. If the re-test fails, a patrol is mandatory.

When a Red Flag Warning condition is declared, Field Operations will closely monitor the NFDRS Forecast and other local forecasts to determine the appropriate operational conditions to be implemented. Additionally, BVES's weather consultant provides more detailed and frequent forecast updates. It should be noted that generally Red Flag Warning conditions are assigned to areas much larger than the BVES service area, such as the County of San Bernardino. Therefore, BVES factors in the localized conditions for its service area.

7.3.6.1 Automatic recloser operations

This initiative covers the work associated with **Automatic Recloser Operational Protocols.**

Risk to be mitigated */ problem to be addressed*

[53] The NFDRS can be found at https://gacc.nifc.gov/oscc/predictive/weather/index.htm#. The entire BVES system is in Predictive Service Area SC10.

High speed clearing refers to the ability to clear faults using automatic reclosers and fast-curve sensitive relay settings. Traditionally, electrical circuits were designed to automatically open and close to detect and isolate faults. In many cases, the relays make three attempts to isolate a fault condition and each potential attempt could cause an electrical spark, which could be a source of ignition. Today, many utilities are implementing modern controls that allow them to designate a normal setting and a wildfire setting. The latter allows utilities to reduce the number of corrections attempts to prevent ignition. This can be coupled with SCADA systems for remote control of the equipment.

Initiative selection *("why" engage in activity)*

"why" engage in activity

BVES installed S&C's Pulse Closer Fault Interrupters across its major 34 kV system auto-reclosers. This technology provides the settings necessary to reduce electrical ignition, while also helping mitigate power outages and equipment damage by using low energy pulses to test for faults.

Alternatives

BVES considered alternatives as part of the planning before the initiative began. BVES continues to monitor the implementation and alternatives to reduce wildfire risk in the most effective and efficient manner possible.

Region prioritization *("where" to engage activity)*

All of BVES's service territory is in Tier 2 and Tier 3 high risk wildfire service areas. Recloser operations will be focused on the highest risk circuits. In the Tier 3 HFTD, there is only one recloser and it is disabled during fire season. There are no other automatic actuating devices in the HFTD Tier 3 area. The recloser in the HFTD Tier 3 area is a new device (< 3 years-old) that is pulse conditioned (lowers test current to about 10% of load when testing) as discussed above. BVES is able to prioritize its recloser deployment as needed. At this time, BVES is not replacing or upgrading any recloser devices.

Progress on initiative

BVES spent $19,870.12 (OPEX) on this initiative in 2021.

Forecasted spend (OPEX) in 2022 is $20,400, $21,000 in 2023, and $21,600 in 2024. The RSE value for this initiative is 25.5.

Currently, efforts in this initiative are dedicated to operations and maintenance of the recently installed reclosers. In 2023, BVES will start to automate additional field switches as discussed below.

Future improvements to initiative

In 2023, BVES plans to automate nine 34 kV field switches and four 4 kV switches. All of these switches are in the HFTD Tier 2 area and will be connected to SCADA. These switches are being selected to offer BVES improved operational control of its system to enhance switching operations to mitigate the extent PSPS events.

7.3.6.2 Protective equipment and device settings

This initiative covers activities related to **Protective Equipment and Device Settings**.

Risk to be mitigated */ problem to be addressed*

Traditionally, electrical circuits were designed to automatically open and close to detect and isolate faults. In many cases, the relays make three attempts to isolate a fault condition and each potential attempt could cause an electrical spark, which could be a source of ignition. Today, many utilities are implementing modern controls that allow them to designate a normal setting and a wildfire setting. The latter allows utilities to reduce the number of corrections attempts to prevent ignition. This can be coupled with SCADA systems for remote control of the equipment. Additional protective equipment, such as switches, and other device configurations are paramount to establishing a more automated and sensorized system, giving BVES optimal insight into real-time activities of the grid.

Currently BVES has not implemented any Enhanced Power Line Safety Settings (EPSS), fast trip settings, or fast curve settings on its protective devices. BVES utilizes the settings derived from engineering coordination studies for each circuit. These studies establish settings to optimize public safety and protection of utility and customer equipment.

Initiative selection *("why" engage in activity)*

"why" engage in activity
This is an ongoing program to establish effective protective equipment project scopes and device settings for applicable assets on BVES's system.

Alternatives
BVES does not have any alternatives to consider at this time.

Region prioritization *("where" to engage activity)*

All of BVES's service territory is in Tier 2 and Tier 3 high risk wildfire service areas. If, after conducting coordination studies, BVES adopts EPSS, fast trip, or fast curve settings, BVES will prioritize such changes on the highest risk circuits.

Progress on initiative

There is no recorded spend in 2021 as this is a newly established initiative. Forecasted budget (OPEX) for this initiative is $12,500 in 2022, $12,800 in 2023, and $13,200 in 2024. The RSE value for this initiative is 46.6.

BVES current plans to review coordination studies and plan which studies should be updated. A sequenced plan will be developed to update the coordination studies, which will be prioritized on the "high risk areas" BVES has identified for PSPS.

Future improvements to initiative

Once a sequenced plan for conducting coordination studies is developed, BVES will begin contracting with qualified engineering firms and updating its protective settings. BVES will task the engineering firm to provide traditional (normal) settings and settings to mitigate wildfire. For the wildfire mitigation settings, BVES will task the engineering firm to determine the probability of false trips when compared to normal settings. BVES does not expect to begin to conduct coordination studies until 2023.

7.3.6.3 Crew-accompanying ignition prevention and suppression resources and services

This is not an applicable program for BVES.

***Risk to be mitigated** / problem to be addressed*

BVES does not have an ignition prevention and suppression resource service initiative. BVES is able to conduct work with associated fire risk by de-energizing work areas as applicable. BVES's small size allows the workforce to pivot to low-risk work on high fire threat days or conduct a training day for its staff. This is true for its contracted power line staff as well who have a detailed program and checklist to outline necessary precautions based on the Fire Index Rating (FIR). BVES does not see reduced productivity overall with this method and has not missed a program target.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES does not have this initiative. BVES is able to conduct work with fire risk by de-energizing work areas as applicable. If special circumstances arise where this would be necessary, BVES would contract this work out as part of the project.

Alternatives
BVES does not have this initiative. BVES is able to conduct work with fire risk by de-energizing work areas as applicable. If special circumstances arise where this would be necessary, BVES would contract this work out as part of the project.

***Region prioritization** ("where" to engage activity)*

BVES does not have this initiative. BVES is able to conduct work with fire risk by de-energizing work areas as applicable. If special circumstances arise where this would be necessary, BVES would contract this work out as part of the project.

Progress on initiative

BVES has no recorded spend for this initiative activity.

There are no current plans for the next year.

Future improvements to initiative

BVES does not have any specific future improvements identified at this time.

7.3.6.4 Personnel work procedures and training in conditions of elevated fire risk

This initiative covers **Personnel Sufficiency // High Risk Conditions Protocol** activities.

***Risk to be mitigated** / problem to be addressed*

BVES will enforce operational changes when a RFW issuance or when its weather consultant forecasts high risk conditions through local weather stations and the NFDRS reports. This initiative is critical to ensuring safe operations during routine and specialized work taking place within the service area.

During high fire threat weather, BVES suspends all work, by BVES staff or its contractors, that might produce sparks or create fire hazards. Due to BVES's small size, BVES and its contractors are able to pivot to other low risk work during such conditions.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
During a potential emergency or significant event, a rapid response, with specific resources can reduce the risk of the event leading to a wildfire. BVES has a Wildfire Infrastructure Protection Team (WIPT). Given the need for capabilities during wildfire incidences and other emergencies, the WIPT aligns with BVES's Emergency Response Team (ERT). Both teams consist of the Utility Manager, Field Operations Supervisor, Service Crew, and Customer Service staff.

The Utility Manager oversees the WIPT. The Field Operations Supervisor will direct field activities and operations during the emergency. The Service Crew (or Dutyman outside normal working hours) will provide initial field response to the emergency. Additional linemen will be called out as needed. Furthermore, Customer Service staff and/or additional staff may be called out to assist with notification procedures as needed. Other staff may be called out at the direction of the Utility Manager to assist, as needed. For example, Engineering staff may be called out to assist linemen in monitoring local wind speeds.

Reports of wires sparking or smoke could lead to a wildfire. The Utility Engineer & Wildfire Mitigation Supervisor has issued operational guidelines or procedures to follow in the event BVES receives a report of potential fire such as "arcing, sparks, smoldering, smoke, or fire" or other emergency reports involving the overhead distribution system. Examples of reports could include customer, or third party reported arcing, sparking, smoke, or fire sightings. These procedures will be at the discretion of the Utility Manager and, given the event, will require prompt and decisive action to place the system in a safe condition.

Alternatives
No comparable alternative exists. The rapid response of personnel to an emergency event is an essential practice to reduce the risk of a wildfire.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. BVES WIPT and ERT can respond to anywhere in the BVES service territory but will pay particular attention to higher risk areas.

Progress on initiative

BVES spent $7,727.27 (OPEX) on this initiative activity in 2021. Forecasted spend in 2022 (OPEX) is $7,900, $8,200 in 2023, and $8,400 in 2024. The RSE value for this initiative is 73.8.

BVES will continue to train staff on these procedures and exercise them during PSPS drills and exercises. Additionally, BVES will discuss high fire risk procedures with its contractors and make sure their actions are in line with BVES's policies. BVES will update procedures based on lessons learned and information exchanges with other utilities.

Future improvements to initiative

BVES will update procedures based on lessons learned and information exchanges with other utilities. Each year, BVES reviews its policies and procedures and will do so for high fire threat days.

7.3.6.5 Protocols for PSPS re-energization

This initiative covers **PSPS Re-Energization Protocol** activities.

***Risk to be mitigated** / problem to be addressed*

This initiative is attributed to the design and execution of procedures for de-energization and re-energization protocols. The objective is to prepare a plan to provide restoration services quickly and safely while maintaining reliability standards.

During a PSPS event, BVES deploys WRTs to high-risk areas. Under such conditions, the WRTs constantly patrol looking for damage and hazardous vegetation. When a line is de-energized, and if conditions are safe to work, the WRTs will begin repairing the damage and removing the hazardous vegetation. Once conditions requiring PSPS clear, BVES WRTs will patrol the de-energized lines, clear any damage or hazardous vegetation then restore power. If there is no damage, the longest it should take to patrol a line is approximately two hours with most circuits less than one hour.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES considers PSPS as a measure of last resort driven by a combination of extreme fire threat weather, fuel moisture, wind, and situational awareness information to protect the community against ignition threats from energized circuits. Although BVES has never had to implement PSPS, BVES is committed to reducing the scope, frequency, and duration of PSPS events should it be necessary, and will only implement PSPS when the safety risk of imminent fire danger is greater than the impact of de-energization.

Protocols for re-energization serve to determine an optimized approach to address affected circuits in a manner that protects the community from additional risks. As BVES continues to reduce ignition risk, BVES anticipates the likelihood to need to use its PSPS to become even more remote, but BVES will continue to evaluate the risk and necessity for its use.

Alternatives
There are no identified alternatives for this initiative activity.

***Region prioritization** ("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. BVES WRT will perform the duties listed above anywhere in the BVES service territory but will pay particular attention to higher risk areas.

Progress on initiative

BVES spent $7,948.05 in procedural updates over the course of 2021.

In 2022, BVES plans to update its PSPS Plan to align with Phase 3 guidelines of the proactive de-energization proceeding directives. Additionally, BVES will conduct training with WRTs on restoration procedures and will exercise the procedures during PSPS drills.

Projected spend in 2022 (OPEX) is $28,200, $29,000 in 2023, and $29,900 in 2024. The RSE value for this initiative is 14.

Future improvements to initiative

BVES will endeavor to incorporate lessons learned across California regarding the use of PSPS and will update its PSPS Plan (attached to this WMP as **Appendix B**) and Emergency Response Plan (attached as **Appendix C**) accordingly.

7.3.6.6 PSPS events and mitigation of PSPS impacts

This initiative covers the work associated with **PSPS Mitigation Activities.**

***Risk to be mitigated** / problem to be addressed*

This initiative is attributed to work surrounding the reduction of PSPS impacts in the event of a future activation. BVES has developed a plan to limit the scope and scale of proactive de-energization on its community members.

BVES installed sectionalizing devices to isolate high risk areas identified as potential likely PSPS areas. These areas can be isolated from the system to minimize the number of affected customers. Additionally, there are no “downstream” customers in lower risk areas that will be affected by isolating these high-risk areas.

BVES maintains its 8.4 MW power plant at the ready should SCE invoke a PSPS interrupt service to BVES. As discussed in the grid hardening section, BVES is pursuing an energy storage project which is in the planning phases.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES considers PSPS as a measure of last resort driven by a combination of extreme fire threat weather, fuel moisture, wind, and situational awareness information to protect the community against ignition threats from energized circuits. Although BVES has never had to implement PSPS, BVES is committed to reducing the scope, frequency, and duration of PSPS events should it be necessary, and will only implement PSPS when the safety risk of imminent fire danger is greater than the impact of de-energization.

As BVES continues to reduce ignition risk, BVES anticipates the likelihood to need to use its PSPS to become even more remote, but BVES will continue to evaluate the risk and necessity for its use. Finally, this initiative aims to continue BVES’s ongoing program for designing, executing, and improving upon protocols to conduct PSPS events, including development of advanced methodologies to determine when to use PSPS, and to mitigate the impact of an activation on affected customers and local residents.

Alternatives
There are no identified alternatives for this initiative activity.

***Region prioritization** ("where" to engage activity)*

All of BVES’s service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES’s service area is small (32 square miles). Additionally, BVES’s HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

While BVES prioritizes resources on WMP initiatives in the HFTD Tier 3 first, it then prioritizes resources within the remainder of its service area (HFTD Tier 2) according to the process described in **Section 7.2** including utilizing the Fire Safety Matrix Model, the PSPS high risk areas, and the REAX Engineering consequence and risk maps.

Progress on initiative

BVES spent $7,594.80 in procedural updates over the course of 2021.

In 2022, BVES plans to update its PSPS Plan to align with Phase 3 guidelines of the proactive de-energization proceeding directives. Additionally, as discussed in the grid hardening section, BVES is making improvements to the reliability of its power plant and planning an energy storage project. These efforts will continue in 2022 and into 2023.

Projected spend in 2022 (OPEX) is $7,800, $8,000 in 2023, and $8,300 in 2024. There is no identified RSE value for this initiative.

Future improvements to initiative

BVES will endeavor to incorporate lessons learned across California regarding the use of PSPS and will update its PSPS Plan (attached to this WMP as **Appendix B**) and Emergency Response Plan (attached as **Appendix C**) accordingly.

As discussed in the grid hardening section, BVES is pursuing an energy storage project which is in the planning phases. It is anticipated that this project will be completed in 2024. This project coupled with the existing power plant will be able to significantly mitigate loss of power due to SCE invoking a PSPS event on power supply lines to BVES.

7.3.6.7 Stationed and on-call ignition prevention and suppression resources and services

BVES does not have an established program or project under this initiative. BVES is small and both its Line Crews as well as the contracted crews are able to manage work such the high-risk work is not conducted on high fire threat days. BVES and its contractors can easily pivot to low-risk activities on short notice due to its small size. For example, if a high fire threat day occurs with little notice, BVES can pivot to other de-energized work or to training, which it has at the ready. For example, BVES can pivot from covered wire or pole replacement work to de-energized work.

BVES's vegetation management contractor has protocols in place for high fire threat weather. For example, on "Very High" fire threat conditions, BVES will require crews, staff and contractors, to:

- Evaluate the weather conditions to ensure they are safe to work in.
- A Dedicated Fire Watch must be assigned to the jobsite.
- There must be a trailer-mounted water tank or alternative water delivery method at the jobsite. 120 gallons with 200 feet of hose.
- No chainsaw operations allowed – only hand saw use permitted.

***Risk to be mitigated** / problem to be addressed*

This initiative may include costs associated with contracted fire staff or related suppression equipment used or stationed at worksites. This allows the utility to quickly suppress small ignitions and prevent a large-scale wildfire from starting.

BVES does not have stationed an "on-call" ignition prevention and suppression resources and services. BVES relies upon BBFD and CAL FIRE for fire response activities. Due to the close working relationship between BVES and these agencies and the compact size and limited resources of BVES, this approach is sufficient to provide the necessary ignition prevention and suppression services. Also, as discussed above, BVES and its contractors are able to plan around high fire threat days with little to no loss of production when viewed on an annual basis.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity

BVES does not have this initiative. The utility is able to conduct work with fire risk by de-energizing segments of the electrical equipment work areas as applicable. If special circumstances arise where this would be necessary, BVES would contract this work out as part of the project.

Alternatives

BVES has investigated contract services for firefighting support but has not made a determination of need. BVES has not had a reportable wildfire in recent years. Additionally, the utility has determined that local fire districts suffice any small area ignition risk along with resources that the utility personnel and contractors maintain in their vehicles.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. If undertaken, this initiative would be applicable to any area within the HFTD where such field work is performed.

Progress on initiative

BVES has no recorded spend for this initiative activity. While there are no current plans to contract fire suppression resources for the next year, BVES will continue to monitor and manage its work and the work of its contractors such that spark producing work or work with the potential to produce sparks is not conducted on high fire threat day.

Future improvements to initiative

BVES will continue to evaluate its policies to not conduct certain work that produces sparks or has the potential to produce sparks on high fire threat days. Based on experience, lessons learned, and techniques other utilities are utilizing, BVES will frequently evaluate its approach and is open to making adjustments if there is a compelling reason to do so.

7.3.7 Data Governance

This section is revised to address RN-BVES-22-06: BVES has misinterpreted data management initiatives.

Data Governance is an enabling investment that supports the overall effort of mitigating wildfires. Proper data governance will support the tracking of events that could lead to a wildfire, tracks the progress of electric system upgrades, and enables the ability to provide information to "other" parties.

BVES recognizes the importance of carefully tracking and managing WMP data for all its activities and initiatives performed in accordance with this WMP. BVES records and manages data collected from numerous sources, in varying formats, and in several storage locations in the execution of its wildfire mitigation efforts. Table 7.3-9 below highlights the types of data collected and the repository in use by BVES for such data.

Table 7.3-9: Detailed Data Information

Data Source	Storage Location	Planned Next Steps	Storage Type (Excel, GIS, etc.)

Vegetation Management	Partners & Spreadsheet Database	Migration to iRestore (cloud-based) software Oct. 2022	Excel, Geo Database
Substation Inspections (GO 174)	Paper-based-database	Migration to iRestore (cloud-based) software Oct. 2022	Binder
GO 165 Inspections	iRestore	None planned	Cloud-based
LiDAR Inspections	Spreadsheet and web portal	Planning to import into Geo Database	Excel, Shapefile
UAV Inspections	Spreadsheet and web portal		Excel, Geo Database
Covered Conductor	Spreadsheet		Excel, Geo Database
Pole Replacement	Spreadsheet		Excel, Geo Database
Pole Remediation	Spreadsheet		Excel
Pole Assets	Spreadsheet		Excel
Fire Wrap	Spreadsheet		Excel, Geo Database
Fuse Replacement	Spreadsheet		Excel, Geo Database
VM QA/QC Inspections	Web Portal		Excel
Asset Inspection QA/QC	Spreadsheet		Excel
Outage Log	Spreadsheet		Excel, Geo Database

BVES is continually updating its data gathering and managing resources and tools. Equally important is having the ability to track electric system upgrades in a GIS database. Having this information in a standard format supports BVES's ability to continuously improve its risk mitigation process.

BVES GIS system does not currently support the sharing data with key stakeholder agencies, such as the CPUC and CAL FIRE, but BVES provides its data in accordance with regulatory requirements.

In order to support the above, BVES has an ongoing initiative to update GIS records in the format agreed upon by the OEIS.

7.3.7.1 Centralized repository for data

This initiative covers **GIS-Based Application** activities.

Risk to be mitigated */ problem to be addressed*

BVES's lack of a centralized data repository limits BVES's staff to quickly and accurately access data and share it in a timely manner with staff or other stakeholders. It can also create situations where data isn't normalized in a consistent format across platforms.

Initiative selection *("why" engage in activity)*

"why" engage in activity
This initiative will improve BVES's ability to gather, track, and disseminate data across BVES, with certain stakeholders, and to the OEIS. Designing, maintaining, hosting, and upgrading a platform that supports storage, processing, and utilization of all utility proprietary data and data compiled by the utility from other sources.

BVES engaged the support of a consultant to identify gaps and make recommendations for methods to address its GIS process and to immediately update the records in the required format. This initiative will result in a common data definition, increase digitization of field work activities, and update system interfaces to automate data flow into GIS for OEIS reporting.

Using the OEIS GIS Data Reporting Requirements and Schema as a guide, initial data governance steps are being taken to define the system of record and assessing initial data quality for each of the required feature datasets in the OEIS schema.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. The marginal expense of developing a database for just the HFTD Tier 3 areas would not be worth the minimal value of maintaining a separate database.

Progress on initiative

BVES spent $225,547.80 (OPEX) under normal business operations in preparing work associated with this activity's objective in 2021.Projected spend (OPEX) in 2022 is $101,300, $84,800 in 2023, and $87,300 in 2024. The RSE value for this initiative is 0.75.

BVES is in the process of updating its GIS systems which will serve as its centralized repository for data and has engaged a contractor to assist with this effort. BVES also recently hired a GIS specialist to digitize BVES's assets, outages, inspections, service territory characteristics, and initiatives. This effort is proposed to be completed in 2022.

Currently, this initiative is focused on gathering the required OEIS GIS feature datasets and updating the asset and risk event data.

This initiative is broken into the following components:

Asset Lines & Points: Update GIS interfaces to pull asset condition details from source systems and transform it into OEIS format for reporting.

Risk Events: Define roles, procedures, and common data definitions for managing risk event data across multiple departments.

By the end of 2021 50 percent of GIS were updated to the correct format.

Future improvements to initiative

This will be an ongoing effort as technologies continue to improve. BVES also will work to tie in its GIS with its SCADA improvements and distribution automation efforts. A BVES consultant will be providing recommendations on improvements in the overall process. These improvements will be considered and evaluated. BVES will continue to evaluate using internal resources verses using a consultant to support the GIS requirements.

7.3.7.2 Collaborative research on utility ignition and/or wildfire

This initiative covers **GIS-Based Applications // Research on Ignition Discovery** activities.

***Risk to be mitigated** / problem to be addressed*

Numerous cutting-edge technologies and improved practices are discovered or refined through the implementation of collaborative research with other outside entities including universities or research groups could identify methods to protect the community, reduce ignitions, and save ratepayer funds. Without participating in such efforts BVES may lag other utilities in such efforts. BVES seeks to enhance existing modeling and mapping capabilities by contracting with shared networks, which aggregate risk threats and current conditions to assist the utility in daily operations and in preparation for WMP planning.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES is interested in developing and executing research work on utility ignition and wildfire topics in collaboration with other non-utility partners, such as academic institutions and research groups, to include data sharing and funding as applicable to reduce fire risks to the community and its system.

BVES has not conducted and is not proposing to conduct any research proposals to identify novel methods of reducing wildfire risk. Due to its small size and limited customer base, BVES will track new and proven techniques, technologies, and methods researched and implemented at other utilities, the national laboratories, in academia, and elsewhere and identify opportunities to conduct pilot programs and implement changes that have proven successful in cost-effectively reducing wildfire risk.

BVES is open to collaborating on research projects on wildfire mitigation and would support outside organizations such as universities performing research in this area. For example, BVES provided a letter of support for Department of Civil and Environmental Engineering, University of California – Davis research proposal to the California Energy Commission (CEC) on wildfire risk assessment and mitigation under changing climate conditions (CEC GFO-18-301) in March 2019 and was willing to support the research effort in its service area, as applicable. The proposal did not gain approval.

Alternatives

No comparable alternative exists.

***Region prioritization** ("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of conducting collaborative research on utility ignition and/or wildfire in a prioritized manner, is minimal. BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend this effort to cover all of the HFTD Tier 2 areas for essentially no incremental cost. BVES would welcome collaborative research on utility ignition and/or wildfire for its entire service area.

***Progress on initiative** (amount spent, regions covered) and plans for next year*

BVES has no recorded spend for this initiative activity since there have not been any initiatives identified. BVES will continue to welcome any R&D efforts, should they arise and make financial sense for BVES and its customers. BVES will discuss its willingness to collaborate on R&D efforts with joint utilities and other entities at T&D conferences.

Future improvements to initiative

BVES welcomes any R&D efforts, that makes sense for a utility the size of BVES, should they arise. BVES will discuss its willingness to collaborate on R&D efforts with joint utilities and other entities at T&D conferences.

7.3.7.3 Documentation and disclosure of wildfire-related data and algorithms

This initiative covers **GIS-Based Applications // Data Sharing Activities**.

***Risk to be mitigated** / problem to be addressed*

Failure to publicly disclose wildfire-related data and algorithms may reduce the likelihood that a flaw that may exist in the data or algorithms will be discovered.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES is working to design and execute processes to document and disclose wildfire-related data and algorithms to accord with rules and regulations, including use of scenarios for forecasting and stress testing.

Alternatives
No comparable alternative exists.

***Region prioritization** ("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of conducting collaborative research on utility ignition and wildfire in a prioritized manner, is minimal. BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend this effort to cover all of the HFTD Tier 2 areas for essentially no incremental cost.

Progress on initiative

BVES spent $8,168.83 (OPEX) under normal business operations in preparing work associated with this activity's objective in 2021. Projected spend (OPEX) in 2022 is $8,400, $8,600 in 2023, and $8,900 in 2024. The RSE value for this initiative is 69.4.

BVES has an ongoing effort to document and disclose all of its wildfire related data and algorithms. As noted above, there is also an ongoing GIS improvement project. As BVES improves its capabilities, it will share the data with the OEIS and publicly via its website.

Future improvements to initiative

BVES is an active participant in Energy Safety's Risk Model Working Group and will utilize the exchange of information and lessons learned from the participants to improve its ability to introduce and utilize probabilistic risk models and mapping. BVES will share its data so that the joint utilities may develop databases with meaningful data on failure mechanisms and ignitions.

7.3.7.4 Tracking and analysis of risk event data

This initiative covers **GIS-Based Applications // Risk Event Tracking Activities**.

Risk to be mitigated */ problem to be addressed*

This initiative allows BVES to identify risk events, including near-miss events, to evaluate its operations, risk reduction efforts, and responses.

Initiative selection *("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives*

"why" engage in activity
BVES invests in tools and procedures to monitor, record, and conduct analysis of data on near-miss events in order to analyze them and identify opportunities to improve its efforts to further reduce wildfire risks.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles); therefore, the marginal expense of conducting collaborative research on utility ignition and/or wildfire in a prioritized manner, is minimal. BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend this effort to cover all of the HFTD Tier 2 areas for essentially no incremental cost.

Progress on initiative

BVES has conducted these activities for years as part of its operating expenses. BVES spent $7,064.93 (OPEX) under normal business operations in preparing work associated with this activity's objective in 2021. Projected spend (OPEX) in 2022 is $7,300, $7,500 in 2023, and $7,700 in 2024. The RSE value for this initiative is 10.3.

Currently, BVES analyzes each outage and spark producing event to determine whether it is a wildfire near miss event. Factors that go into the analysis include documenting weather conditions, NFDRS, and other wildfire drives at the time of the event. The near miss events and evaluations are maintained in a log (outage log) for future analysis. BVES will transition this database to its GIS by the end of 2023. BVES continues to make progress in implementing the GIS data schema that Energy Safety requests the utilities utilize. This effort includes geolocation of risk events for future data analysis.

Future improvements to initiative

As discussed above, the near miss events and evaluations that are maintained in a log (outage log) for future analysis, will be transitioned to the GIS by the end of 2023. Additionally, BVES will develop a process for management to periodically review the data from the GIS to inform WMP decision making and resource allocation.

7.3.8 Resource Allocation Methodology

7.3.8.1 Allocation methodology development and application

This initiative covers **Resource Allocation Methodology // Personnel Sufficiency** activities.

Risk to be mitigated */ problem to be addressed*

This initiative allows for the development of a prioritization methodology for personnel and financial resources, including application of said methodology to utility decision-making.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES seeks to maximize the use of its limited resources to efficiently allocate financial and human capital by establishing a methodology that would evaluate spending to achieve the most significant risk reduction per dollar spent.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles.

While BVES prioritizes resources on WMP initiatives in the HFTD Tier 3 first, it then prioritizes resources within the remainder of its service area (HFTD Tier 2) according to the process described in **Section 7.2** including utilizing the Fire Safety Matrix Model and the REAX Engineering consequence and risk maps.

Progress on initiative *(amount spent, regions covered) and plans for next year*

BVES addresses this activity through regular OPEX spending of $7,727.27 in 2021 and plans to spend $7,900 in 2022, $8,200 in 2023, and $8,400 in 2024. The RSE value for this initiative is 73.8.

Section 7.2 discusses BVES's WMP Project Selection and Prioritization Process, which describes the process BVES management utilizes to identify WMP projects, select WMP projects, sequence WMP projects and sequence specific WMP project work scopes for each WMP or WMP update.

Future improvements to initiative

As discussed in **Section 7.2**, BVES conducts a review of projects each WMP or WMP update using a defined process to prioritize projects according to the risk reduction, RSE, and other factors (siting, permitting, availability of materials, planning, etc.). From this process, resources are then allocated. In this process, BVES constantly incorporates lessons learned and knowledge gained from experience and outside the organization to improve the process.

7.3.8.2 Risk reduction scenario development and analysis

This initiative covers **Risk Mapping Program // Risk Reduction Scenario Modeling** activities.

Risk to be mitigated */ problem to be addressed*

The CPUC has not required BVES to conduct a Risk Assessment and Mitigation Phase (RAMP). However, BVES evaluates enterprise risk using a risk-based decision-making framework and has adopted a Fire Safety Circuit Matrix to prioritize wildfire risk and evaluate wildfire risk mitigation. The combination of these methods allows for both a comprehensive analysis of enterprise-wide safety risk and wildfire related assessment to generate an effective proxy wildfire ignition risk assessment. BVES Risk-Based Decision-Making Framework effectively targets circuits and assets to assure initiatives that provide the greatest mitigation benefits are properly prioritized. Accordingly, BVES is working with a contractor to develop a model to better quantify ignition risk drivers and associated probabilities to assist in determining which initiative mitigations to targeted circuits and assets that will provide the greatest benefit to wildfire risk reduction. This project will be completed in 2022. This is further described in **Section 7.3.1.1.**

Initiative selection *("why" engage in activity)*

"why" engage in activity
This effort will allow BVES to better identify wildfire risks under present and future conditions across its service territory. This will further enable BVES to target its risk reduction efforts to maximize the risk reduction benefit for each wildfire mitigation initiative.

Alternatives
BVES has engaged in several other risk identification exercises including the Fire Safety Circuit Matrix and analysis of the RSE but there is no direct comparable alternative to this initiative.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles; thus, BVES is able to prioritize the HFTD Tier 3 and extend the effort to cover all of the HFTD Tier 2 areas. Accordingly, this effort will cover the entirety of the BVES service territory.

Progress on initiative

BVES spent (OPEX) $19,597.40 on this in 2021. In 2022, BVES will be contracting with Technosylva in an effort to secure a subscription platform for live risk reduction event scenario planning along with other components.

BVES has allocated $29,800 for this initiative in 2022, $30,700 in 2023, and $31,600 in 2024 (OPEX). The RSE value for this initiative is 2.87.

Technosylva will be developing risk modeling that takes into account the grid hardening efforts by BVES to assist gauging the progress in risk reduction and to predict future risk reduction. This effort includes incorporating the Wildfire Analyst Enterprise (WFA-E) subscription and platform the Wildfire Risk Reduction Model (WRRM) to inform WMPs and WMP Updates. This effort will be mostly quantitative, which will be an improvement on BVES's current models that rely on SME input. BVES expects the transition from SME reliant models to probabilistic models based on quantitative data to be conducted over the next 2-3 years with a goal of fully implementing this by the end of 2024.

Future improvements to initiative

As mentioned above, BVES is in transition from SME-based risk models to probabilistic models based on quantitative data. Finding good data to feed the models will be challenging. BVES is working with its expert risk modeling contractor to ensure the models are loaded with the best data available.

Furthermore, BVES is an active participant in Energy Safety's Risk Model Working Group and will utilize the exchange of information and lessons learn from the participants to improve its ability to introduce and utilize probabilistic risk models and mapping.

7.3.8.3 Risk spend efficiency analysis (not to include PSPS)

This initiative covers **Risk Mapping Program // Risk Spend Efficiency** activities.

Risk to be mitigated */ problem to be addressed*

This activity is intended to promote efficient use of BVES resources to identify initiatives that provide the most risk reduction per dollar spent.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES is building and investing in tools, procedures, and expertise to support analysis of wildfire mitigation initiative risk-spend efficiency, in terms of MAVF and/ or MARS methodologies.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Additionally, BVES's HFTD Tier 3 is less than 10 percent in area and less than 1 percent (<2 circuit miles) in terms of circuit miles. Accordingly, all of BVES's service territory will be covered by its RSE analysis.

BVES has broken out RSEs for HFTD Tier 3 and HFTD Tier 2 initiatives separately.

Progress on initiative

BVES spent (OPEX) $19,597.40 on this in 2021. In 2022, BVES will be contracting with Technosylva in an effort to secure a subscription platform for live risk reduction event scenario planning along with other components.

BVES has allocated $29,800 for this initiative in 2022, $30,700 in 2023, and $31,600 in 2024 (OPEX). The RSE value for this initiative is 2.87

BVES has broken out RSEs for HFTD Tier 3 and HFTD Tier 2 initiatives separately. BVES will further refine its RSE calculations for HFTD Tier 3 and HFTD Tier 2 initiatives separately. Each year BVES will reassess the risk reduction, remaining risk, and annualized cost for each initiative. This reassessment each year yields updated RSE values.

Future improvements to initiative

As discussed in the previous initiative, BVES is transitioning to more probabilistic models based on quantitative data (target end of 2024); therefore, as risk reduction values change for each applicable initiative, RSE values will change.

Furthermore, BVES is an active participant in Energy Safety's Risk Model Working Group and will utilize the exchange of information and lessons learned from the participants to improve its ability to produce insightful RSEs.

7.3.9 Emergency Planning and Preparedness

BVES has conducted tabletop and functional exercises in 2021 and 2022 to test the validity of its Emergency Response and Disaster Plan (ERDP). These tests have yielded lessons learned that BVES has been able to incorporate into its PSPS Plan update, along with the required changes as the plan is required to move to Phase III. In addition to the tabletop and functional exercises described above, BVES has participated in its partner utility's (SCE) exercises in 2022.

BVES has an ongoing effort to participate in PSPS events though the PUC and Energy Safety. These events are monitored and tracked, and the posted lessons learned from the CA IOUs are documented for review by the BVES PSPS team. Any and all aspects of the CA IOU lessons learned that could bolster the BVES PSPS Plan are workshop and, if necessary, updates are made to the plan.

For greater detail regarding PSPS and BVES's PSPS Plan see **Section 8**.

7.3.9.1 Adequate and trained workforce for service restoration

This initiative covers **Personnel Sufficiency // Service Restoration Activities**.

Risk to be mitigated */ problem to be addressed*

Utilities need adequate staff trained for service restoration following a service interruption to ensure quick and safe restoration of service. Additionally, utilities should have in place emergency contracts and mutual aid agreements to augment its workforce for service restoration activities.

Initiative selection *("why" engage in activity)*

"why" engage in activity
To ensure BVES can safely and quickly restore service following an interruption, BVES has taken actions to identify, hire, retain, and train qualified workforce to conduct service restoration in response to emergencies, including short-term contracting strategy and implementation. BVES also has long standing

contracts for mutual aid that can provide additional assistance if necessary. The qualifications for the BVES staff and short-term contractors are provided in **Section 5.4**.

Alternatives

No comparable alternative exists.

***Region prioritization** (“where” to engage activity)*

All of BVES’s service areas are in Tier 2 and Tier 3 high risk wildfire service areas. Accordingly, this applies to the entirety of the BVES service area. BVES’s service area is small (32 square miles). While BVES prioritizes HFTD Tier 3 WMP initiatives over the Tier 2, the Tier 3 area is less than 2 circuit miles (< 1 percent of the BVES system). Therefore, BVES is able to easily meet its commitments in the HFTD Tier 3 with respect to this initiative and dedicate resources to the HFTD Tier 2 without any degradation.

Progress on initiative

BVES includes spending on this initiative in its normal OPEX budget with $7,845.13 spent in 2021 and is allocating (OPEX) $8,100 in 2022, $8,300 in 2023, and $8,500 in 2024. The RSE value for this initiative is 9.19.

BVES engages in the following activities to ensure its work force is able to effectively conduct restoration efforts:

- BVES ensures vacancies for service restoration staff are filled as soon as possible and that crews are fully staffed.
- BVES manages vacation and off-site staff training to ensure there is always sufficient service restoration personnel available.
- BVES manages manager and supervisor vacation and “off the mountain” time such that there is always a highly capable supervisory element available to lead and direct service restoration efforts in accordance with BVES procedures.
- All BVES staff are required to live in the BVES service area.
- BVES conducts training and at least once per year conducts an exercise to practice service restoration command and control and field activities.
- Following any outage, the Field Operations Supervisor reviews lessons learned with the team to ensure continual improvement.
- BVES maintains emergency contracts current for power line work (overhead and underground), civil work (underground facilities), transmission and distribution engineering and planning, crane services, welding services, backhoe and digging equipment operators, power plant operators, emergency generation services, switchgear and device technical support, IT support for critical applications and hardware, etc.
- BVES is of member of the California Utilities Emergency Association (CUEA), which is a mutual aid organization that allows utilities to seamlessly assist each other when resources are constrained.
- BVES is a member of the Bear Valley Mountain Mutual Aid Association, which provides members mutual assistance during community emergencies. The organization consists of first responders, local government and agencies, utilities and telecommunications companies, non-profit emergency aid organizations, key community stakeholders, etc.

Future improvements to initiative

BVES is continuously engaged in learning from outage events to gain knowledge and make improvements from lessons learned. Currently, the emergency contracts in place and the mutual aid agreements are more than adequate to support service restoration. This has been fully demonstrated over the years when BVES experienced major (storm related) outages. BVES will discuss service restoration strategies and resourcing with other utilities to further improve in this area.

7.3.9.2 Community outreach, public awareness, and communications efforts

This initiative covers the **Community Outreach Program** activities.

***Risk to be mitigated** / problem to be addressed*

An informed community can be prepared for and reduce wildfire risks to the community, increase cooperation on utility wildfire efforts, and reduce friction and complaints during or following wildfire prevention and mitigation activities including, but not limited to, PSPS activations, tree attachment removal, and vegetation management activities.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES has taken and will continue to take actions to identify and contact key community stakeholders; increase public awareness of emergency planning and preparedness information; and design, translate, distribute, and evaluate effectiveness of communications taken before, during, and after a wildfire, including Access and Functional Needs populations and Limited English Proficiency populations in particular.

Alternatives
No comparable alternative exists.

***Region prioritization** ("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. Accordingly, this applies to the entirety of the BVES service area. BVES's service area is small (32 square miles) and its customer base is small (approximately 24,600 meters). Therefore, the marginal expense of targeting all customers compared to targeting select groups of customers and subareas within BVES's small service area in a prioritized manner, is minimal. However, BVES does prioritize the following in community engagement efforts where it is feasible and cost effective:

- Within the service area, BVES has identified several "High Risk Areas", which are shown in Figure 8.6.1: High Risk Areas for PSPS Consideration and Customer Count. Community engagement prioritizes the customers in these areas.

- Additionally, like other utilities, BVES has medical baseline and AFN customers. These customers are also prioritized in targeted community engagement activities.

Progress on initiative

BVES conducts this activity through its normal operations budget spending $79,204.76 in 2021. BVES plans on increasing this effort in 2022 to $81,600 and in 2023 and 2024, BVES budgets $84,000 and $86,500, respectively. The RSE value for this initiative is not currently measured.

In 2022, BVES will verify and update as needed its points of contact (primary, secondary, & tertiary) lists for first responders, local government and agencies, utilities and telecommunications companies, key community stakeholders, local media, and critical infrastructure before the fire season. Additionally, BVES will test these lists via their selected preferred method of contact.

BVES sends every customer an AFN survey.

BVES will implement its key stakeholder web portal and implement its use in 2022.

BVES aims to engage the community (via radio, newspaper, website, social media, etc.) at least 360 times in 2022. Furthermore, BVES will conduct community and stakeholder briefs on PSPS and Wildfire Mitigation prior to the fire season and again in September prior to Santa Ana wind period. BVES also sends customer engagement surveys to measure awareness of BVES wildfire mitigation, PSPS, and other emergency response efforts. Recent survey results show some increases and some decreases of public awareness about BVES's programs. BVES is analyzing the results and exchanging information with other utilities to improve awareness.

BVES invited stakeholders and community members to take part in Tabletop and Functional Exercises of its PSPS Plan.

Future improvements to initiative

BVES will use its periodic customer surveys to determine the effectiveness of its community engagement efforts and will main changes as appropriate. Additionally, BVES will be requesting feedback from first responders, local government and agencies, critical facilities, other utilities and telecommunications, and other community stakeholders on the effectiveness of BVES's community engagement with them.

Additionally, BVES will engage key stakeholders (first responders, local government and agencies, utilities and telecommunications companies, key community stakeholders, local media and critical infrastructure) to gain their perceptions on the effectiveness of BVES's outreach efforts.

BVES is committed to plans to increase the number of stakeholder meetings held to four times per year and will try to involve public relations.

7.3.9.3 Customer support in emergencies

This initiative covers the **Emergency Response Plan** activities.

Risk to be mitigated */ problem to be addressed*

This effort is intended to ensure customers stay informed during emergencies which could help customers find the resources they need, such as access to a community resource center, prevent them from engaging in risky behavior and free up BVES resources to address and resolve the emergency.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES engages in this initiative to ensure there are sufficient resources dedicated to customer support during emergencies, such as website pages and other digital resources, as well as dedicated phone lines to keep customers informed of emergency conditions, assistance available, and the estimated duration of the emergency.

Customers often seek and require support during wildfires and public emergencies. BVES developed support plans to provide assistance when and where it is needed directly to those impacted.

As ordered by the CPUC, BVES provides emergency residential and non-residential customer protections to wildfire victims. Example protections include billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, and specific support for low income and medical baseline customers.

In the event the Governor of California declares a state of emergency because a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service or resulted in the degradation of the quality of utility service, BVES shall implement certain customer service actions described below. This section provides an overview of the protocols for compliance with requirements adopted by the CPUC regarding activities to support customers. The protocols span outage reporting, customer billing, support for low-income customers, and other forms of customer support.

Support for Low Income Customers - The Customer Care team will freeze low-income customer accounts, stop billing, and stop all California Alternative Rates for Energy (CARE) High-Usage tracking. The Customer Service Supervisor will work with implementation contractors and emergency assistance programs to update affected customers on eligibility requirements and enroll them in assistance programs.

Billing Adjustments - The Customer Care team freezes accounts and stops billing during the wildfire event to ensure bills are not estimated or generated for affected customers. All customers affected by the disaster will be notified that billing will be discontinued and BVES will prorate bills, including any monthly minimum charges, to the customer during the wildfire event. Billing will resume once the case is closed by the Customer Care & Billing (CC&B) technical team, upon notice from the Supervisor.

Deposit Waivers - The Customer Care team provides a designated customer contact for all affected customers. The BVES contact reports within CC&B for up to one year from the date the emergency ends. This allows BVES to easily track the customer's account, so when service is re-established, the utility knows to waive any associated fees and to expedite customer re-connection.

Extended Payment Plans - The Customer Care team freezes all payments on affected customer's account to avoid affecting their credit. All affected customers are notified that an extended payment plan option is available for any past due payments.

Suspension of Disconnection and Nonpayment Fees - The Customer Care team freezes affected customer accounts, so disconnections and nonpayment fees are not generated during the wildfire event. Once the emergency ends, the Supervisor or Specialist contacts the CC&B team to "close" all affected customer cases. This automatically transitions the customer's account back to the normal state. BVES simultaneously begins assisting with service restoration and deposit waivers.

Repair Processing and Time - During emergencies, BVES establishes specialized repair teams to expedite repair processing. If additional support is needed, BVES leverages mutual aid programs with other emergency response resources and works with electrical contractors to ensure timely service restoration. Exact timing is dependent on the nature of the situation.

Access to Utility Representatives - The BVES Engineering Inspector arranges for connections and facilitates expedited services. Leveraging its IVR and two-way-text system, BVES is able to manage thousands of phone calls and redirect customers to the appropriate utility representative.

Activities related to emergency planning and response are part of ongoing efforts and are not bound by a specified execution date. BVES continues to work with partners to seek input on emergency response planning and enhance with unique efforts or cooperative plans.

Alternatives
No comparable alternatives exist.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Accordingly, this applies to the entirety of the BVES service territory.

Progress on initiative

This is and will be an ongoing activity. BVES spent $60,178.11 in OPEX in 2021.

BVES has budgeted $62,000 in 2022, $63,800 in 2023, and $65,800 in 2024. The RSE value for this initiative is not measured.

Future improvements to initiative

BVES will continue to develop improved solutions for providing customer support during emergencies and disasters. This includes cross training for staff to be able to provide service connection inspections 24/7. BVES is also working to ensure its Customer Information System (billing system) is capable of supporting the intended customer support during emergencies and disasters.

BVES is improving its ability to input data into its GIS and develop overlays. BVES will be striving, in the next 1-2 years, to be able to identify customers that are disconnected from service due to disaster damage and the status of restoring service (e.g., damaged, repairs in progress, repairs complete waiting for city green tag, ready for BVES inspection, etc.). This advancement will be very useful in understanding the scope of work to be completed to return customers to service and triaging where to optimally place resources.

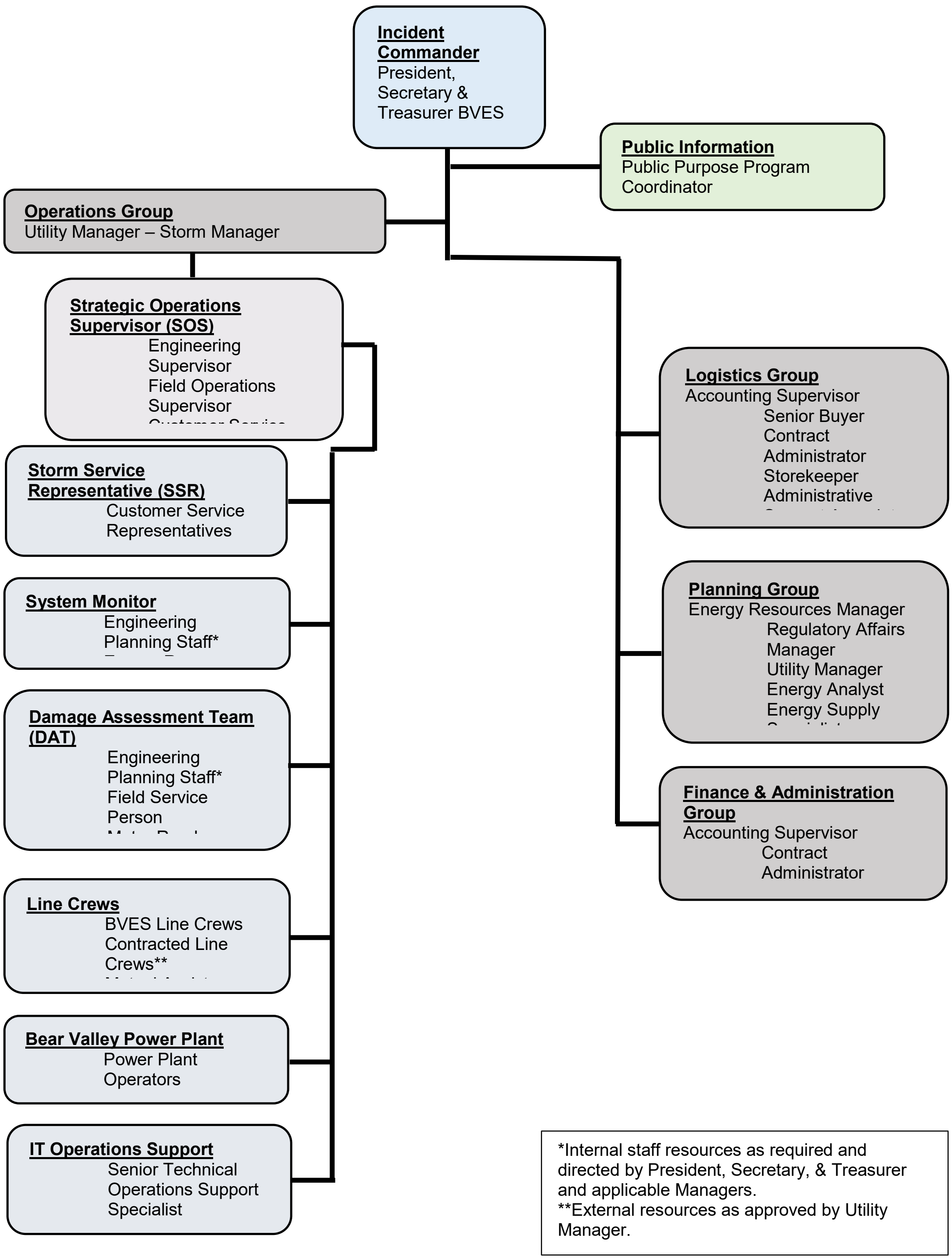
7.3.9.4 Disaster and emergency preparedness plan

This initiative covers the **Emergency Response and Disaster Plan** activities.

Risk to be mitigated */ problem to be addressed*

When disaster strikes, BVES will be relied upon to take quick and decisive actions. Such actions could fail to achieve the objective or even be counterproductive without sufficient planning to develop the proper communication protocols, coordination both internally and externally. BVES responds to emergencies in accordance with its Emergency Response & Disaster Plan (ERDP), which is compliant with GO 166 Standards for Operation, Reliability, and Safety During Emergencies and Disasters. A copy of the ERDP is forwarded to the Commission annually per GO 166 and attached to this WMP as **Appendix C**. In responding to emergencies, BVES staff is organized based on the Standardized Emergency Management System (SEMS) as interpreted by the Company and outlined in the Emergency Preparedness and Response Plan. **Figure 7.3-8** illustrates how the BVES staff aligns with the SEMS organizational structure during an emergency.

Figure 7.3-8: BVES Emergency Organization

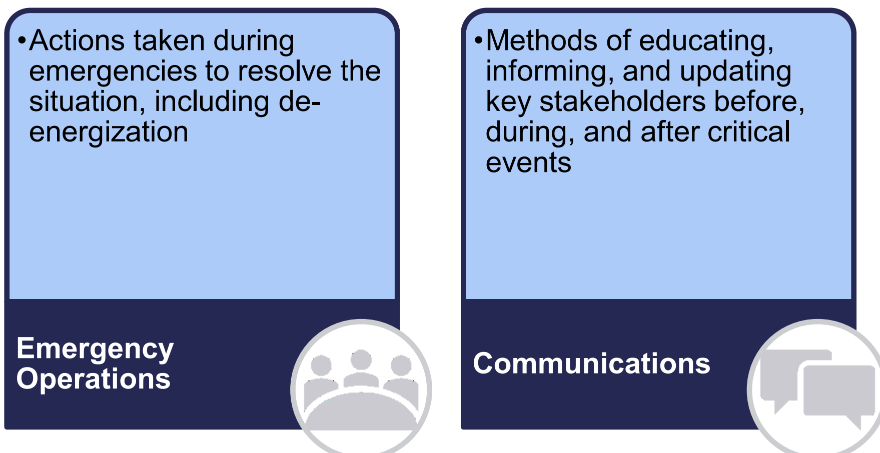


Additional guidance is provided in this section. These procedures apply to both situations that may affect the electrical system (e.g., proactive de-energization) or the area at-large (e.g., wildfire event). This section details these plans, including compliance, and roles and responsibilities for executing the plan.

Plan Overview

The ERDP reflects the BVES belief that it is important to have proactive planning and close coordination with local governments, first responders, mutual aid and expert agencies, other stakeholders, and customers. Specifically, the Emergency Preparedness and Response Plan includes two main components: (1) an emergency protocol plan and (2) a communications plan, similar to the PSPS Plan.[54] **Figure 7.3-9** below describes these two complementary components.

Figure 7.3-9: Emergency Preparedness and Response Components



Due to BVES's unique service territory, several key stakeholders are involved in emergency preparedness and response. These stakeholders include local governments and agencies as well as location-specific organizations, including resorts and business groups. With this understanding, BVES has outlined all key stakeholders. **Table 7.3-10** provides the stakeholder list. BVES will review the list annually and update it, as needed.

The PSPS Plan is attached as Appendix B

Table 7.3-10: BVES Emergency Preparedness and Response Stakeholder List

Stakeholder Group	Description
Customers	Any person or organization who receives electricity from BVES or is impacted by BVES's services to the community
Local Government / Agencies	Big Bear Area Regional Wastewater Agency (BBARWA) Bear Valley Community Hospital Bear Valley Unified School District Big Bear Chamber of Commerce Big Bear Airport District Big Bear City Community Services District (CSD) Big Bear Fire Department Big Bear Lake Water Department (DWP) Big Bear Mountain Resort Big Bear Municipal Water District (MWD) San Bernardino County Sheriff's Department CAL FIRE California Highway Patrol Arrowhead Area California Department of Transportation City of Big Bear Lake San Bernardino Fire Department and Office of Emergency Services Southwest Gas Corporation US Forest Service Communication Companies (internet, cellphone and landlines)
Mountain Mutual Aid Association	Organization with 31 members, including utilities, business groups, and non-government organizations committed to the community
State	Warning center at the Office of Emergency Services San Bernardino Director of Safety Enforcement Division Others, as requested

Initiative selection *("why" engage in activity)*

"why" engage in activity

Emergency Response preparations are long-term processes for which each BVES Department must be constantly ready, especially during the winter months. Preparations for emergency response are best achieved through training on the ERDP, continuous evaluation of the plan, coordination and outreach with external stakeholders, provisioning emergency response materials and equipment, and establishing mechanisms to rapidly bring emergency response resources to the service area such as mutual aid agreements, contracts, and other partnering agreements.

The ERDP is provided to all BVES employees to ensure an efficient, effective, and uniform response during an emergency situation. BVES recognizes the importance of an integrated ERDP in order to safely provide for the energy needs of our customers and the requirements of our stakeholders in the event of an emergency. BVES strives to meet customer needs through effective risk assessment, mitigation, preparedness, response, and communications. Our vision is to achieve excellence in emergency management.

In the event of a wildfire or other emergency event, BVES invokes its ERDP and staffs up its Emergency Operations Center to coordinate activities to restore service. The BVES restoration strategy and priorities are detailed in the ERDP. BVES's WIPT oversees response and restoration activities. In the event that additional staff is needed, BVES leverages mutual aid agencies, including the City of Big Bear Lake staff and local aid organizations. The utility also engages temporary employees and contractors on an as-needed basis.

The ERDP requires that in responding to emergencies, the Company's staff shall be organized largely based on the SEMS as interpreted by the Company. The SEMS structure utilized by BVES is a utility compatible Incident Command Structure (ICS) framework designed to manage emergency incidents and events.

In an effort to further improve emergency preparedness and response, BVES implemented the iRestore APP, which provides First Responders (Big Bear Fire Department and San Bernardino Sheriff's Department – Big Bear Lake Detachment) and BVES's internal Damage Assessment Teams a tool to quickly document and report problems along its distribution system and facilities to Dispatch. The iRestore Responder Application will provide emergency and remedial response needs at the ground-level allowing public safety partners, utility personnel, and contractors to coordinate and execute emergent corrections and quickly identify at-risk events to bolster near miss tracking in the future.

Alternatives

No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Accordingly, this applies to the entirety of the BVES service territory. BVES's ERDP covers the entire service area since it would be inefficient to have separate ERDPs for the HFTD Tier 3 and Tier 2 areas. Within the plan, BVES addresses conditions for the Radford Line (34 kV), which is the lone line in the HFTD Tier 3. All other circuits are located in HFTD Tier 2.

Progress on initiative

This is and will be an ongoing activity covered in OPEX funding. BVES spent $7,109.09 in 2021.

BVES plans to spend (OPEX) $7,300 in 2022, $7,500 in 2023, and $7,700 in 2024. The RSE value for this initiative is 10.2.

BVES reviews its ERDP each year and following each implementation of the ERDP due to actual emergency or drill for lessons learned and possible improvements. Additionally, BVES will conduct an internal assessment of how well managers and supervisors have complied with the preparatory requirements (e.g., emergency contracts, contact lists, emergency materials in stock, etc.). Another aspect of this initiative will be to test all of the types of communications referred to in the ERDP (inbound and outbound).

Future improvements to initiative

Each year the ERDP is reviewed and updated as applicable due to changes in requirements, lessons learned, changes to the grid, and suggestions from stakeholders in the community. For example, once the Radford Line covered conductor project is completed, BVES will update its ERDP to reflect the new capabilities of the Radford Line (e.g., not de-energizing it from April to October).

7.3.9.5 Preparedness and planning for service restoration

This initiative covers the **Emergency Response and Disaster Plan** activities.

Risk to be mitigated */ problem to be addressed*

Restoration of power service following an event or emergency can be challenging and presents safety concerns. Consequently, restoration of service must be conducted in an orderly, methodical manner to ensure it is achieved safely and as quickly as possible.

BVES employees are provided the necessary tools, training, and protocols to support emergency restoration activities because employee and public safety is of the utmost importance. BVES employees are trained to respond to outages, storms, wildfires, and other emergency events efficiently and safely. In accordance with the ERDP, BVES employees must coordinate effectively with other public first responders (police, fire, emergency management). BVES has built a SEMS structure that ensures everyone is trained and prepared for their assigned emergency roles. Periodic tabletop exercises are used for preparation for these low frequency, high impact public emergency events.

Initiative selection *("why" engage in activity)*

"why" engage in activity

BVES undertakes these actions to limit the duration of service interruptions and promote the safety of its workers and the community. To this end, BVES is engaged in the development of, and revisions to, plans to prepare the utility to restore service after emergencies, such as developing employee and staff trainings, and to conduct inspections and remediation necessary to re-energize lines and restore service to customers.

Outage events and emergencies are rarely similar in all respects; therefore, this general restoration strategy is constructed to provide the EOC Team with a scalable and flexible restoration strategies that can be employed as required to deal with the unique aspects of each major outage and emergency event. Restoration strategies details are contained in **Appendix C**, Section 4.3.

Alternatives

No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Within the plan, BVES addresses conditions for the Radford Line (34 kV), which is the lone line in the HFTD Tier 3. All other circuits are located in the HFTD Tier 2. Accordingly, this applies to the entirety of the BVES service territory. BVES's ERDP covers the entire service area since it would be inefficient to have separate ERDPs for the HFTD Tier 3 and Tier 2 areas.

HFTD

Progress on initiative

This is and will be an ongoing activity covered in OPEX funding with $6,800.00 spent in 2021. BVES has budgeted $7,000 in 2022, $7,200 in 2023, and $7,400 in 2024. The RSE value for this initiative is 5.36.

Each year BVES conducts a drill if it did not invoke its Emergency Operations Center during the year. The drill or real-life scenario serves as a source of lessons learn, which BVES seeks and then makes updated to the ERDP if appropriate. Additionally, BVES conducts training on the ERDP with staff. Furthermore, BVES managers and supervisors ensure that emergency contracts are in place and that emergency response materials are stocked onsite. BVES is an active member of the California Utilities Emergency Association (CUEA) and maintains the ability to request additional responses should they be needed in emergency response.

Future improvements to initiative

BVES does not have any specific future improvements identified at this time. Each year the ERDP is reviewed and updated as applicable due to changes in requirements, lessons learned, changes to the grid, and suggestions from stakeholders in the community. For example, once the Radford Line is completed, BVES will update its ERDP to reflect the new capabilities of the Radford Line (e.g., not de-energizing it from April to October).

7.3.9.6 Protocols in place to learn from wildfire events

This initiative covers the **Emergency Response Plan** activities.

Risk to be mitigated */ problem to be addressed*

Establishing protocols to learn from wildfire events is meant to ensure that BVES learns and adapts its practices following wildfire events within its service territory, across California, and in other dry mountainous environments.

Initiative selection *("why" engage in activity)*

"why" engage in activity
Bear Valley Electric Service leverages the protocols included in the company's ERP to learn from wildfire events in the same manner the utility learns from any emergency event. The criticality and scope of the BVES ERP has grown over the past few years. To meet these challenges, emergency preparedness and response activities must be systematic, inclusive, and transparent to review incidents in a manner that is aligned with our core values.

In 2022, BVES will develop and implement a formal after-action program (AAP). It is anticipated that a formal after-action process and report will be required after the activation of the emergency plan in order to have formal review process that will include both BVES staff and community partners.

BVES has developed and implemented a continuous improvement approach to wildfire mitigation that analyzes utility wildfire events and seeks to prevent their recurrence and improve the operational practices or emergency response issues that hampered the utility involved in the previous wildfire event. Accordingly, BVES has adopted tools and procedures to monitor effectiveness of strategy and actions taken to prepare for emergencies and of strategy and actions taken during and after emergencies, including based on an accounting of the outcomes of wildfire events.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). BVES's ERDP covers the entire service area since it would be inefficient to have separate ERDPs for the HFTD Tier 3 and Tier 2 areas.

Progress on initiative

This is and will be an ongoing activity covered in OPEX funding. BVES will continue to review CAL FIRE wildfire reports as they are published, exchange information with other utilities on wildfire events they experienced, attend conferences that include wildfire lessons learned, and obtain expert literature on the subject.

BVES spent (OPEX) $6,711.69 in 2021 on this initiative. BVES budgets (OPEX) $6,900 in 2022, $7,100 in 2023, and $7,300 in 2024. The RSE value for this initiative is 5.36.

Future improvements to initiative

While BVES does not have any specific future improvements identified at this time, it is constantly seeking information regarding wildfire lessons learned. BVES monitors universities that have engaged in the subject, seek out conferences and courses that cover wildfire lessons learn, and as mentioned above seek out literature and articles on the matter. BVES is considering engaging BBFD and CAL FIRE to provide briefings to BVES staff.

7.3.10 Stakeholder Cooperation and Community Engagement

7.3.10.1 Community Engagement

This initiative covers the **Community Outreach Program** activities.

***Risk to be mitigated** / problem to be addressed*

This initiative is intended to keep the customer base that BVES services informed on necessary facets of business operations. This initiative also targets improved communication around wildfires and wildfire related activities, if the community needs to be aware of the actions BVES is taking to maintain service during fire season for its customers, and the effort’s effects on rates.

***Initiative selection** ("why" engage in activity)*

"why" engage in activity
BVES engages in this initiative as it feels it is best practice to keep its customers informed on what it is doing both in regular operation and also the actions being taken during fire season to reduce risk.

Community outreach, public awareness, and communications efforts are required to reduce the impact to customers and the community from an event causing interrupting of service and/or poses serious public risks. Effective planning and awareness also assist to limit the scope of extreme events and avoid escalation. BVES has altered how the company addressed the risk of catastrophic wildfires due to the increased presence of potential wildfire due to climate changes and environmental conditions. BVES works year-round to educate customers and the general public and works with community partners to improve outreach, awareness, and communications.

The Energy Resource Manager oversees communications plans and activities. Reporting to the energy Resource Manager is the Customer Service Supervisor, who manages communication activities. BVES’s communication plan includes a two-pronged approach (1) proactive preparation before emergencies occur and (2) notifications during and after emergency events. Communications protocols vary slightly when dealing with stakeholders that include customers, first responders, the local mutual aid association, local government, among other key stakeholders.

The list below describes the goals and methods of informing each of these groups.

Customer Outreach and Notifications: The goal of customer outreach is to educate and prepare customers for fire prevention, proactive de-energization, and other utility infrastructure-related emergencies. Communication formats are planned in English, Spanish, Tagalog, Vietnamese, Chinese, French, Mixteco and Zapoteco for online resources and when requested by customers. BVES is continuing to enhance its community outreach activities and has conducted a self-identified survey process to account for these populations. Details are provided in **Section 8.4** of this 2021 WMP. Indigenous communities surrounding the service area are investigated to account for the unique languages representing English as a Second Language (ESL) speakers. BVES collaborates with other community organizations to assure that a local community resource center is available to customers during emergencies. BVES aligns its communication with other organizations, so it is clear and consistent among the local and state organizations.

Before Emergencies: Proactive outreach includes regular messages related to fire prevention (such as vegetation management, distribution inspection, and de-energization policies) and operational initiatives. This engagement occurs through public workshops, BVES newsletters, social media, website posts, and other forms of media. Special presentations related to fire prevention and preparing for emergencies, including PSPS events, are provided through multiple outlets, including printed material, public service announcements, social media, and special briefings by BVES.

During / After Emergencies: Notifications include BVES-prepared customer-facing statements for staff to disseminate in the case of de-energization and emergencies, including information about timing and location of such events. These notifications occur through news outlets, printed materials, digital media, radio forums, website updates, social media updates, text messages, local government, and agency media (e.g., City of Big Bear Lake's email blasts), and interactive voice response (IVR) calls. Additional forms of communication may be leveraged as new technologies and software become available.

Post-event, BVES provides billing and repair support for affected customers. Billing support may include billing adjustments, deposit waivers, suspension of disconnection, and extended payment plans for standard and low-income customers. Repair support may include regular communications about repair processing and timing and individualized support from a utility representative.

1. Local Government and Agency Engagement and Notification: Communications with local government agencies is essential to BVES's outage and emergency response plans. BVES leadership strives to engage with local agencies in a direct and expedient manner. Coordination and preparation for emergencies, including PSPS, is a shared responsibility between BVES, public safety partners, and local governments; however, BVES is ultimately responsible and accountable for the safe deployment of PSPS. BVES prepares and informs relevant agencies, before, during, and after outages, PSPS, or emergencies. BVES's protocols include establishing a two-way communication channel to help facilitate communications to collaboratively manage the potential impacts of events.

2. Before Emergencies: BVES participates in proactive briefings with the local government to collaboratively plan to minimize the impacts of potential emergencies. These briefings include in-person meetings, emails, and coordinated training and drills. BVES solicits feedback from the local government and other agencies on its emergency preparedness communication plans and overall protocols, to incorporate ongoing improvements.

3. During / After Emergencies: When an emergency occurs, BVES notifies all relevant local government and agencies immediately to ensure proper response coordination. The Customer Care & Operations Support Supervisor and other staff performing customer and public information functions work closely to coordinate with counterparts including the local government and other agencies, providing outage and emergency notifications, estimated time to restore service, and periodic updates as available. BVES continues to provide timely communications to all parties until the situation has been resolved. These notifications happen through phone, text, email and in-person communications.

4. Mountain Mutual Aid Association (MMAA) Participation: The MMAA works in conjunction with the local fire department. BVES's outreach and engagement with the MMAA is similar to the collaborative approach used with local government and agency communications. Specifically, the goal is to inform, prepare, and coordinate closely with community first responders and aid workers.

5. Before Emergencies: Proactive briefings center on how the plan impacts the surrounding community based on BVES's utility infrastructure. Briefings may be conducted through email, training, remote collaboration tools, and in-person meetings, among others. BVES gains valuable feedback from MMAA to harmonize its emergency preparedness, communication plans, and overall protocols to align with other community partners aligned in their goal of public safety.

6. During / After Emergencies: When an emergency occurs, BVES notifies MMAA members immediately to effectuate a coordinated response. BVES continues to provide timely communications and participate in coordinated activities until the situation has been resolved. Communication and notifications happen through phone, text, email and in-person communications, among others.

7. CPUC Reporting: BVES's communication with the CPUC aligns with mandates and requirements.

8. Before Emergencies: BVES submits its Fire Prevention Plan, Wildfire Mitigation Plan, and Emergency Response Plans for review and input. All plans are designed to work together to minimize the impact of outages and infrastructure-related events and, most importantly, protect the public safety.

9. During / After Emergencies: BVES notifies the Director of Safety Enforcement Division (SED) within 12 hours of the power being shut off. BVES also notifies the CPUC and Warning Center at the Office of Emergency Services in San Bernardino within one hour of shutting off the power if the outage meets the major outage criteria of GO 166.

BVES provides a written report to the Director of SED no later than 10 business days after a shut-off event ends per ESRB-8. The utility complies with all analysis and report requests during and after any emergencies. Outage data shall also be included in BVES's annual reliability indices report to the CPUC.

Alternatives
No comparable alternative exists.

Region prioritization *("where" to engage activity)*

All of BVES's service area is in Tier 2 and Tier 3 high risk wildfire service areas. Accordingly, this applies to the entirety of the BVES service area. BVES's service area is small (32 square miles) and its customer base is small (approximately 24,600 meters). Therefore, the marginal expense of targeting all customers compared to targeting select groups of customers and subareas within BVES's small service area in a prioritized manner, is minimal. However, BVES does prioritize the following in community engagement efforts where it is feasible and cost effective:

Within the service area, BVES has identified several "High Risk Areas", which are shown in Figure 8.6.1: High Risk Areas for PSPS Consideration and Customer Count. Community engagement prioritizes the customers in these areas.

Additionally, like other utilities, BVES has medical baseline and AFN customers. These customers are also prioritized in targeted community engagement activities.

BVES prioritizes community engagement specifically targeted at first responders, local government and agencies, critical facilities, other utilities and telecommunications, and other community stakeholders.

Progress on initiative

As part of a small, tight-knit community, collaboration is built into the daily values and way of working at BVES. BVES collaborates with CalOES, county and local governments, independent living centers, and community representatives. BVES engages in quarterly engagements with identified public safety partners and issues routine communication efforts to customers. BVES also provides a pre- and post-season public meeting depicting updates on wildfire mitigation efforts and wildfire and PSPS potential for that year. While BVES has all of the appropriate elements for an effective community engagement program, customer surveys indicate that BVES has room to improve. BVES will focus its attention on the quality of messaging to try to increase awareness in the community.

BVES also sends customer engagement surveys to measure awareness of BVES wildfire mitigation, PSPS, and other emergency response efforts. Recent survey results show some increases and some decreases of public awareness about BVES's programs. BVES is analyzing the results and exchanging information with other utilities to improve awareness.

BVES sends every customer an AFN survey.

BVES spent $29,905.14 in OPEX in these efforts in 2021.

BVES has budgeted (OPEX) $30,700 in 2022, $31,700 in 2023, and no current budget allocation in 2024. The RSE value for this initiative is 10.6.

Future improvements to initiative

BVES will use its periodic customer surveys to determine the effectiveness of its community engagement efforts and will main changes as appropriate. Additionally, BVES will be requesting feedback from first responders, local government and agencies, critical facilities, other utilities and telecommunications, and other community stakeholders on the effectiveness of BVES's community engagement with them.

BVES is committed to increasing stakeholder meetings to four times per year and will try to involve public relations.

7.3.10.2 Cooperation and best practice sharing with agencies outside CA

This initiative covers the **Community Outreach Program // Continuous Learning** activities.

Risk to be mitigated */ problem to be addressed*

This initiative is intended to keep BVES informed of actions being taken to reduce utility wildfire risk. Without communication outside the state of California there is a chance that BVES would miss information that could be beneficial to its wildfire programs.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES engages in this activity to verify that the programs they have developed and the tools that are being used are at an equivalent or higher level to its California counterparts as well as its counterparts outside of the state of California. BVES is implementing a strategy and preparing actions to engage with

agencies outside of California to exchange best practices both for utility wildfire mitigation and for stakeholder cooperation to mitigate and respond to wildfires.

Alternatives
Given the communication-based nature of this initiative BVES does not see alternatives to their current approach. BVES is continually monitoring industry best practice and is open and willing to adjust their program if the need arises.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Accordingly, this applies to the entirety of the BVES service territory. BVES will prioritize obtaining best practices and lessons learned for the HFTD Tier 3 area and then for the HFTD Tier 2 areas.

Progress on initiative

BVES plans to expand its efforts in this initiative area in 2022 and has accordingly increased the projected operational expenditure spending for this initiative. BVES will be participating in several major transmission and distribution (T&D) conferences that provide lessons learned and information on wildfire mitigation and an opportunity to meet with manufactures and vendors of T&D equipment and materials and discuss how they can support BVES's wildfire mitigation efforts.

BVES spent (OPEX) 16,779.21 in 2021 on this initiative activity. BVES forecasts to spend (OPEX) $17,200 in 2022, $17,700 in 2023, and $18,300 in 2024. The RSE value for this initiative is 10.6.

Future improvements to initiative

BVES expects to be more engaged in conferences and workshops and working groups. For example, BVES will attend a major T&D conference scheduled to be held in San Diego in February 2023. Due to close proximity of the conference, BVES intends to send several planning and field staff to the conference.

7.3.10.3 Cooperation with suppression agencies

This initiative covers the **Community Outreach Program // Fire District Engagement** activities.

Risk to be mitigated */ problem to be addressed*

This initiative is intended maintain established relationships with the local, state, and federal suppression agencies so continued support can be provided in reducing BVES's overall fire risk, improving response time, and increasing the number of resources that can be mustered to deal with a potential wildfire within the BVES service territory.

Initiative selection *("why" engage in activity)*

"why" engage in activity
BVES engages in this initiative to verify that the support needed in the instance of a wildfire event is available and confirm BVES programs and procedures are designed in a way to reduce wildfire risk and keep the customers and the area BVES services safe. BVES coordinates with CAL FIRE, federal fire authorities, county fire authorities, and local fire authorities to support planning and operations, including support of aerial and ground firefighting in real-time, including information-sharing, dispatch of resources, and dedicated staff.

Communications with local government agencies is essential to BVES's outage and emergency response plans. BVES leadership strives to engage with local agencies in a direct and expedient manner. Coordination and preparation for emergencies, including PSPS, is a shared responsibility between BVES, public safety partners, and local governments; however, BVES is ultimately responsible and accountable for the safe deployment of PSPS. For PSPS communications, BVES has two-pronged plans for CPUC, local government agencies, and the Mountain Mutual Aid Association.

Alternatives

Given the communication-based nature of this initiative BVES does not see alternatives to their current approach. BVES is continually monitoring industry best practice and is willing to adjust their program if the need arises.

Region prioritization *("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). This applies to the entirety of the BVES service territory.

Progress on initiative

BVES has been coordinating with various stakeholders for years including BBFD, CAL FIRE, the USFS , county fire authorities, mutual aid organizations and more. BVES will continue to improve information sharing and coordination with these organizations and others. BVES meets with BBFD and the Sheriff at least every 2 months. BVES has developed an initiative to provide BBFD, Sheriff, and CHP the iRestore App, which will enable first responders to report directly into BVES's dispatch using their mobile devices (phone) with a picture of the situation and the geo-coordinates for the location. By reporting this way, BVES will have the phone number of the first responder making the report and BVES dispatch will be able to discuss the issue further with the first responder.

BVES spent $7,064.93 of OPEX funds in 2021 towards this effort.

BVES plans to spend (OPEX) $7,300 in 2022, $7,500 in 2023, and $7,700 in 2024. The RSE value for this initiative is 10.6.

Future improvements to initiative

BVES is developing a routine meeting schedule and agenda for BBFD, CAL FIRE, and the USFS. The meetings will focus on BVES wildfire mitigation initiatives, specifically on grid hardening efforts and inspection efforts. BVES will seek feedback on its prioritization of these efforts. BVES had good discussions in the past on evacuation route hardening efforts and would like to bring that type of collaborative effort to the covered conductor project.

7.3.10.4 Forest service and fuel reduction cooperation and joint roadmap

This initiative covers the **Contracted Forester Services // Future Collaborative Work with Land Agencies** activities.

Risk to be mitigated */ problem to be addressed*

This initiative is intended to keep BVES informed on all new and existing approaches to reducing fire related risk as it pertains to the actions taken by local, state, and federal entities. With the additional information that can be ascertained from these relationships BVES can adjust or update their existing wildfire mitigation programs to better reduce their overall wildfire risk and verify continued excellence to their customers. BVES is implementing strategies and taking actions to continue to improve engagement with local, state, and federal entities responsible for or participating in forest management and fuel reduction activities; and design utility cooperation strategy and joint stakeholder roadmap (plan for coordinating stakeholder efforts for forest management and fuel reduction activities).

***Initiative selection** ("why" engage in activity)*

"why" engage in activity

BVES intends to engage in this initiative to verify that the actions they are taking in the wildfire reduction space are industry best practices, as well as continue to facilitate existing relationships if support/knowledge/assistance is ever needed.

Alternatives

No comparable alternative exists.

***Region prioritization** ("where" to engage activity)*

All of BVES's service areas are in Tier 2 and Tier 3 high risk wildfire service areas. BVES's service area is small (32 square miles). Accordingly, this applies to the entirety of the BVES service territory.

Progress on initiative

BVES has conducted these activities for years but did not specifically identify spending towards this effort. Beginning in 2021, BVES began to track spending used towards this end and explore avenues to begin development of cooperation related to forest service and fuel reduction. Additional efforts can be found in **Section 7.3.5**

BVES spent $11,911.56 in 2021 on this initiative activity. BVES plans to spend (OPEX) $13,700 in 2022, $14,000 in 2023, and $14,500 in 2024. The RSE value for this initiative is 0.73

Future improvements to initiative

BVES is looking at two possible future initiatives:

- Developing a more formal joint strategy and policy with the USFS to cooperate on handling fuel reduction in the BVES right of ways..
- Working with a local charity organization that collects and distributes firewood to low-income members of the community. BVES will work with its vegetation contractor to partner with the charity organization and supply wood (for firewood) to the charity. This effort helps low-income members of the community get through cold winters with low costs, promotes goodwill in the community, and it minimizes the amount of wood waste that is transported out the BVES service area.

8 PUBLIC SAFETY POWER SHUTOFF (PSPS)

8.1 Directional Vision for Necessity of PSPS

Describe any lessons learned from PSPS since the last WMP submission and describe expectations for how the utility's PSPS program will evolve over the coming 1, 3, and 10 years. Be specific by including a description of the utility's protocols and thresholds for PSPS implementation. Include a quantitative description of the projected evolution over time of the circuits and numbers of customers that the utility expects will be impacted by any necessary PSPS events. The description of protocols must be sufficiently detailed and clear to enable a skilled operator to follow the same protocols.

When calculating anticipated PSPS, consider recent weather extremes, including peak weather conditions over the past 10 years as well as recent weather years, and how the utility's current PSPS protocols would have been applied to those years.

BVES considers PSPS as a measure of last resort, driven by a combination of extreme fire threat weather, fuel moisture, wind, and situational awareness information to protect the community against ignition threats from energized circuits. Although BVES has never had to implement PSPS, BVES is committed to reducing the scope, frequency, and duration of PSPS events should it be necessary, and will only implement PSPS when the safety risk of imminent fire danger is greater than the impact of de-energization. As BVES continues to reduce ignition risk, BVES anticipates the likelihood to need to use its PSPS to become even more remote, but BVES will continue to evaluate the risk and necessity for its use. Finally, BVES will endeavor to incorporate lessons learned across California regarding the use of PSPS and will update its PSPS Plan (attached to this WMP as **Appendix B**) and Emergency Disaster and Response Plan (attached as **Appendix C**), accordingly.

No direct lessons learned from BVES-initiated activations can be applied to this WMP Update. BVES has not met thresholds to initiate a PSPS event within 2021. The triggering threshold has also not changed based on the implementation of WMP initiatives. In the future, BVES anticipates continued re-designation of high-risk areas to reduce risk designations after years of significant WMP initiative implementation. This is exemplified by **Table 4.3-2**, which denotes the reduction of risk on high priority circuits over time. As mitigations are deployed and real-time modeling capabilities are enhanced, BVES will re-evaluate its PSPS trigger thresholds.

Circuits identified for de-energization and customer impact include North Shore Circuit (1,021 customers), Boulder Circuit (1,063 customers), Lagonita Circuit (946 customers), Clubview circuit (740 customers), Goldmine Circuit (950 customers), and Erwin Lake Circuit (197 customers). In the event that the Radford Circuit is de-energized, the load will be shifted to the Shay Line and no direct customers will be impacted.

PSPS Evolution Timeline

In 2022, BVES plans to contract with Technosylva in an effort to provide real-time situational awareness through on-demand fire spread predictions and impact analysis, wildfire risk forecasting for customer assets and the service area using daily weather prediction integration and asset risk analysis using historical weather climatology. Additional quantitative analysis of this projected evolution will be available over the year with full deployment in 2023.

In mid-2022, BVES is updating its current PSPS Plan and Protocols to align with Phase 3 de-energization guidelines issued under D. 21-06-034.

While BVES does not anticipate an increase in PSPS activation, pre- and post-season activities for PSPS awareness have been made more robust through quarterly engagements with members of the public safety partner network. BVES held a tabletop simulation on April 15, 2022, enabling a run-through process of protocol activation with emergency and fire response personnel. On June 21, 2022, BVES plans to conduct a community awareness workshop to address any pre-season concerns, review its protocols, and forecast for proactive de-energization as part of its functional exercise. BVES will file its annual Pre-Season Report on July 1, 2022.

BVES conducted public outreach and published its vision for necessity of PSPS on its website.[55] Due to previous, ongoing and future grid hardening efforts, the projected risk outlook relative to system hardening efforts carried out on prioritized circuits indicates a lower risk forecast as these initiatives are executed over ten years. This reduces the likelihood and need to initiate PSPS events.

BVES has not initiated any PSPS events over the past three years and does not forecast an imminent need to de-energize in the future based on a one, three, or ten-year forecast. The two tables below correlate high wind events (gusts and sustained winds) with High-Risk Days (days with NFDRS that are Brown, Orange, or Red) over the past 6 years. The data indicates that threshold for BVES to direct a PSPS event was not experienced in the BVES service area.

Table 8.1-1: Highest Daily Wind Gust and Sustained Wind on High-Risk Days

Highest Daily Wind Gust on High-Risk Days							
Wind Gusts	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
>55	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0
40 to 49	1	0	0	0	1	1	2
30 to 39	7	7	5	6	1	5	5
20 to 29	43	78	39	64	27	65	51
<20	56	66	74	59	58	90	27
Highest Daily Sustained Wind on High-Risk Days							
Wind Gusts, Sustained	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
>55	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0
40 to 49	0	0	0	0	0	0	0
30 to 39	0	0	0	0	0	0	1
20 to 29	7	2	6	5	3	7	4
<20	100	149	112	124	84	154	83

[55] BVES, Public Safety Power Shutoff page https://www.bvesinc.com/safety/public-safety-power-shutoff/.

Table 8.1-2: National Fire Danger Rating System (NFDRS) Historic Data

NFRDS	2015	2016	2017	2018*	2019*	2020	2021
G-Low Risk	26	71	109	26	189	108	87
Y-Moderate Risk	232	144	138	169	66	97	187
B-High Risk	105	138	103	122	78	152	90
O-High Risk	0	9	15	7	9	6	0
R-High Risk	2	4	0	0	0	3	0

**NFDRS not available for some days due to Federal Government shutdown*.

Based on the numbers in Table 8.1 above, BVES anticipates no more than one PSPS event in the next five years.

Because BVES has not had to initiate PSPS events, it is not quantifiable to reduce the frequency, scope, or duration of future PSPS events. However, BVES does not view lack of PSPS events as a case for complacency. Accordingly, BVES incorporates PSPS lessons learned from BVES's observation and review of PSPS actions taken by other utilities in California.

In addition to its own plan for proactive de-energization, BVES may also be impacted by PSPS events triggered by SCE, because SCE's system supplies the bulk of energy to BVES's system. Accordingly, BVES closely monitors and coordinates with developments at SCE and is ready to respond to any SCE PSPS that may cut imports to BVES.

Because BVES has never enacted a PSPS and believes that there is a low likelihood that BVES will need to enact a PSPS in the future, BVES does not have a defined vision for the continued evolution of its PSPS Plan. However, BVES recognizes climate change is changing historical weather patterns and fire conditions including severity and length of the fire season. In a future WMP update, BVES will assess the historical outlook of fire weather conditions over the last ten years and determine any instances where a PSPS activation would have been justified using BVES's PSPS thresholds to assist in scenario development of forecasted risk. Taking no action to harden circuits or reduce the impact of PSPS events, would leave BVES's customers and stakeholders vulnerable to future extreme fire weather events that could necessitate PSPS. Therefore, over the course of the ten-year planning period, grid hardening initiatives, enhanced vegetation management programs, more robust forecasting capabilities, and increased situational awareness will continue to keep the likelihood of PSPS activation remote. Additionally, BVES plans to continue to coordinate with public safety partners and community members as well as provide any PSPS Plan and wildfire safety updates ahead of each wildfire season.

Instructions for Table 8.1-1:[56]

Rank order, from highest (1 – greatest anticipated change in reliability or impact on ignition probability or estimated wildfire consequence over the next 10 years) to lowest (9 - minimal change or impact, next 10 years), the characteristics of PSPS events (e.g., numbers of customers affected, frequency, scope, and duration), regardless of if the change is an increase or a decrease. To the right of the ranked magnitude of impact, indicate whether the impact would be a significant increase in reliability, a moderate increase in reliability, limited or no impact, a moderate decrease in reliability, or a significant decrease in reliability. For each characteristic, include comments describing the expected change and expected impact, using quantitative estimates wherever possible.

BVES found no subsequent evidence to update the table for anticipated characteristics of PSPS use over the next 10 years. The ranking order from the 2021 WMP Update remains accurate.

Table 8.1-3: Anticipated Characteristics of PSPS Use Over Next 10 Years (Table 8.1-1)

Rank (Order 1-9)	PSPS Characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
2	Number of customers affected by PSPS events (total)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
3	Number of customers affected by PSPS events (normalized by fire weather, e.g., Red Flag Warning line mile days)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
6	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (total)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
4	Frequency of PSPS events in number of instances where utility operating protocol requires deenergization of a circuit or portion thereof to reduce ignition probability (normalized by fire weather, e.g., Red Flag Warning line mile days)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.

[56] Due to an earlier table included in Section 8.1, labeling is updated to reflect the required table from the 2022 WMP Guidelines template

Rank (Order 1-9)	PSPS Characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
5	Scope of PSPS events in circuit events, measured in number of events multiplied by number of circuits targeted for deenergization (total)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
7	Scope of PSPS events in circuit events, measured in number of events multiplied by number of circuits targeted for deenergization (normalized by fire weather, e.g., Red Flag Warning line mile days)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
8	Duration of PSPS events in customer hours (total)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
9	Duration of PSPS events in customer hours (normalized by fire weather, e.g., Red Flag Warning line mile days)	No change	BVES has not initiated any PSPS events. Based on historical weather patterns, BVES assesses that the need to initiate a PSPS would be a rare event due to winds not being high during dry weather periods.
1	Other_– Loss of supply due to SCE activated PSPS	Increase	Partial or complete loss of SCE supplies is a possibility, which would result in BVES having to likely implement rolling blackout procedures.

8.2 Protocols on Public Safety Power Shut-off

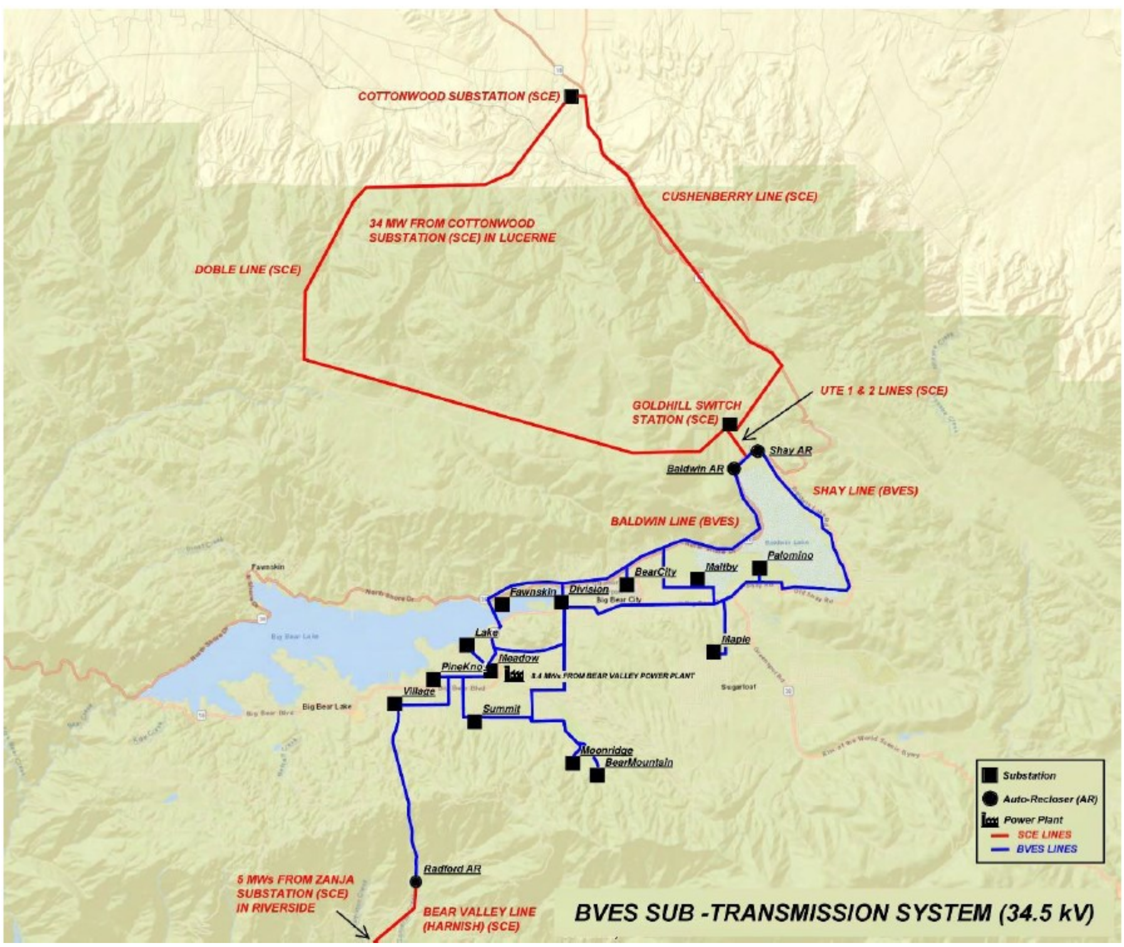
Describe protocols on Public Safety Power Shut-off (PSPS or de-energization), highlighting changes since the previous WMP report:

The protocols on PSPS, including the following elements, are described in detail in the attached PSPS Plan in **Appendix B** to this WMP. No changes are applicable for this 2022 WMP Update. BVES is currently working to update its existing PSPS Plan to align with D. 21-06-034 Phase 3 guidelines.

Method used to evaluate the potential consequences of PSPS and wildfires. Specifically, the utility is required to discuss how the relative consequences of PSPS and wildfires are compared and evaluated. In *addition, the utility must report the wildfire risk thresholds and decision-making process that determine the need for a PSPS.*

While BVES does not have a formal quantitative method to evaluate the potential consequence of PSPS and wildfires, lessons learned can be drawn from similar utilities across the state. Once BVES fully implements Technosylva's services, BVES will be able to have a near real-time ability to quantify the consequence of wildfires, and, therefore, the ability to evaluate the compare the wildfire consequence and risk to the consequences of a PSPS event. BVES has not experienced a wildfire event or a PSPS activation to capture challenging and successful takeaways. Currently, the highest probability for triggering a PSPS event within the BVES service territory is the loss of SCE's energy imports to the BVES service area due to a SCE-directed PSPS of the SCE supply lines. BVES imports from SCE are subject to PSPS activation initiated by SCE. SCE may activate a proactive de-energization of these lines even if these circuits within the BVES service area and conditions do not meet BVES PSPS thresholds. To address the possibility of SCE-directed PSPS events, BVES proposes to construct an energy storage project of approximately 5 MW/20 MWh (four-hour) lithium-ion utility-grade battery serving the BVES service area. In conjunction with the existing Bear Valley Power Plant and potential utility scale solar, BVES would be able to initially meet its energy demands during a supply drop from SCE for several hours depending on load shedding strategy. BVES will continue with project planning and evaluation of an energy storage and solar facility within the BVES service territory, though, this project timeline has been extended due to siting delays.

Figure 8.2-1: BVES Supply Lines, Sources of Power and Sub-Transmission System



The table below outlines BVES's action plan for addressing partial or complete loss of power due to SCE supply line de-energization events.

Table 8.2-1: BVES Action for SCE Lines De-Energized due to PSPS

Condition	BVES Action
SCE De-energizes Doble or Cushenberry Line for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Energize Radford Line as needed to meet load demand. If the Utility Manager deems it necessary, energize the Radford Line as needed for reliability. Startup of the BVPP as needed to meet load demand. No reduction on load necessary, since the Doble and Cushenberry are capable of carrying the other's load. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines
SCE De-energizes Bear Valley Line for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If Radford is energized, shift loads to Shay Line prior to deenergizing for PSPS. Generally, this should be done about 4 hours prior to the SCE de-energizing the line. If needed, start up the BVPP to meet load demand. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines
SCE De-energizes Doble or Cushenberry and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Since the Doble and Cushenberry are capable of carrying the other's load, follow the procedure for "SCE De-energizes Bear Valley Line for PSPS" above. Prepare for potentially losing all SCE supply lines into BVES service area. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Doble and Cushenberry Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If not already done, energize the Radford Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, shift as much of the load to the BVPP and Radford Line as follows: Open the Shay and Baldwin automatic reclosers. "Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order. Start up the BVPP, place enginators on-line and increase load to within the combined capacity of the BVPP and Radford Line. Implement BVES Emergency Response Plan for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures. Prepare for sustained BVPP operations and rolling blackouts. Frequently monitor distribution circuit loads.
SCE de-energizes Doble, Cushenberry, and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If the Radford Line is energized, shift loads to the Shay Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, perform the following: Start up all of the BVPP enginators. Reduce system load to within the capacity of the BVPP by isolating distribution circuits as directed by the Field Operations Supervisor. Once system load is matched with the BVPP capacity, open the Shay and Baldwin automatic reclosers. Implement BVES Emergency Response Plan for sustained loss of all SCE supply lines including "rolling blackout" procedures.

Scope, scale, and frequency of PSPS activations will be mitigated through BVES's seasonal operational posture that directs the following actions taken throughout the year:

1. The Radford Line is to be de-energized from April to October or else otherwise recommended by the Field Operations Supervisor. Re-energization can be achieved should the forecasted demand require additional generation, for planned maintenance, system upgrades, or other directed action. No redundancy degradation exists with this operational protocol since the supply lines from the Lucerne area are separated and independent of one another. The Radford Line assists to supply power during winter high load periods as BVES profiles as a winter-peaking utility.

2. From April to October, BVES will place certain auto-reclosers, fuse TripSavers, and switches in "manual" operation such that they will not shut and test upon detection of a fault. A specific list of switched mechanisms will be derived ahead of each fire season to ensure load forecasts align with present conditions to the best ability possible. The completion of the Grid Automation Project, which establishes connectivity and control of these devices, will necessitate a policy revision or re-evaluation.

    a. When an auto-recloser, switch, or fuse TripSaver that was placed in "Manual" due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is "Green" or "Yellow," the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk of causing fire.

3. Due to reduced load in non-winter period, the Utility Engineer & Wildfire Mitigation Supervisor will develop specific settings for auto-reclosers and other protective devices in the field to enhance fire prevention. The list of affected devices will be provided to the Utility Manager and the Field Operations Supervisor. Additionally, the Field Operations Supervisor will be provided the settings that the Field Operations staff will be required to set on each device. Specific dates to enter these reduced settings will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Engineering staff will not change device settings without the Field Operations Supervisor's authorization.

It should be noted that while BVES is able to evaluate its facilities and determine the limiting wind speeds when distribution facilities are possibly at high risk, BVES is not able to determine the strength or health of vegetation surrounding bare conductors outside of the required vegetation clearance zones as well as other structures that may come loose and impact BVES distribution facilities. Therefore, BVES may determine a need to proactively de-energize facilities during high fire threat and high wind conditions. This would be done in close consultation and coordination with local government and agencies. Isolating areas with switching devices allow for sectionalization of the areas affected, which will be communicated to affected parties if a decision to activate PSPS is made.

Strategy to minimize public safety risk during high wildfire risk conditions and details of the considerations, including but not limited to a list and description of community assistance locations and services provided during a de-energization event.

BVES utilizes PSPS as a measure of last resort to protect public safety during times of high fire danger. This is because of the public safety concerns associated with the loss of critical infrastructure and services when power is lost. BVES considers the enactment of a PSPS event as an emergency condition on a level equivalent to natural disasters. BVES uses common emergency response nomenclature that integrates with existing state and local emergency response communication messaging and outreach structures (including the California Alert and Warning Guidelines). BVES describes this in detail in section 6.4 of the attached PSPS Plan in **Appendix B**. Critical facilities will receive prior notification to a PSPS activation. These entities include the emergency services sector, government facilities sector, healthcare and public health sector, energy sector, wastewater and water systems sector, communications sector, chemical sectors, and key partners encompassing local jurisdictions.

Figure 8.2-2: Community Resource Center Operational Procedures

Planned locations and number of standing contracts

BVES has one CRC Located at its Main Facility at: 42020 Garstin Dr., Big Bear Lake, CA 92315

Services provided

Water | Chairs | PSPS information
Representatives | Restrooms | Small first aid kits
Nonperishable Food | EZ up tents for shade
Generators for power I Portable Batteries |
Internet and Phone Access

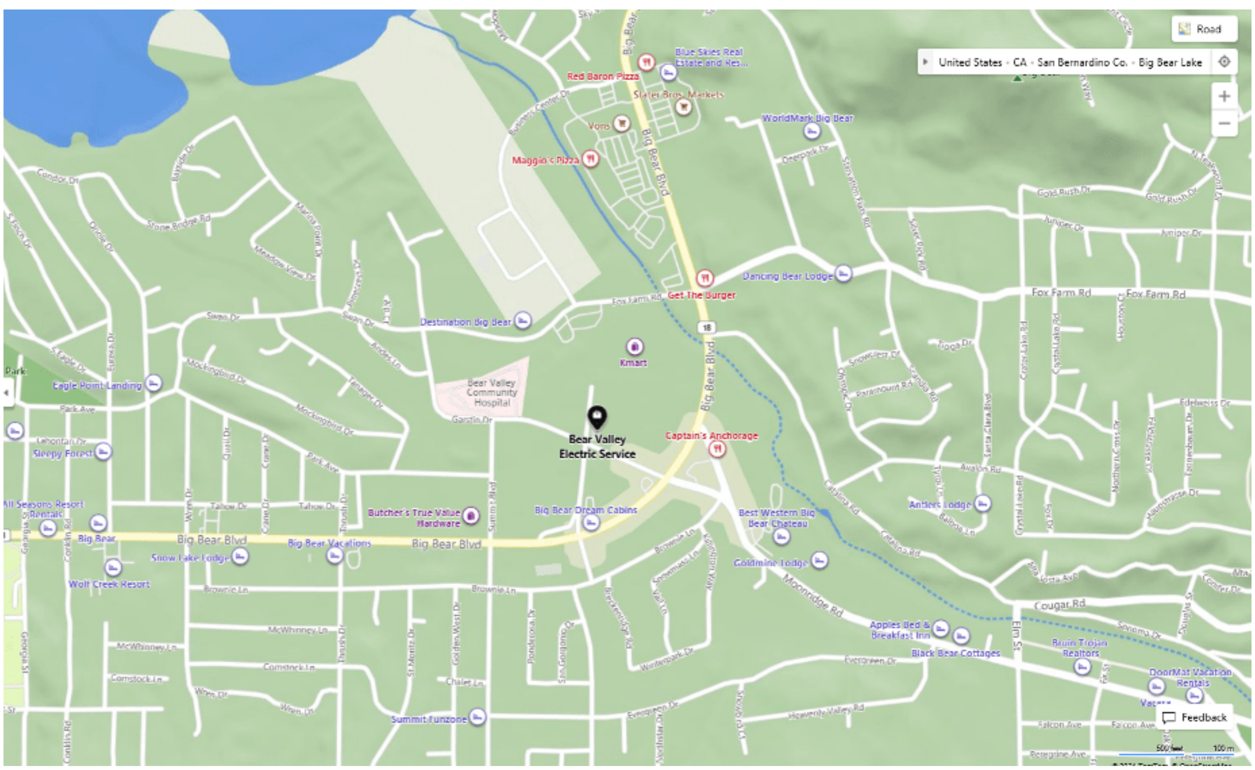
Coordination and Identification

Due to having a relatively small service area (approximately 10 miles end-to-end) and a small staff, BVES opted to locate a CRC at its headquarters, allowing greater use of shared responsibility and resources. First responders, CBOs, local utilities, and critical contacts have been informed that the CRC will be made available during an emergency/PSPS event. CRC is mobile so it can be relocated in the event access to the Main Facility is not available.

Accordingly, BVES has established protocols to help to ensure medical baseline and members of the AFN community receive prior notice through suitable means of communication. For example, not all homes under these characteristics may have access to reliable internet, in which case IVR methods will need to be deployed or physical doorknocker pamphlets distributed.

Additionally, during a PSPS event BVES would open up its Community Resource Center (CRC) at its Main Facility at 42020 Garstin Drive, which is described in **Appendix B** of the attached PSPS Plan.

Figure 8.2-3: CRC Location



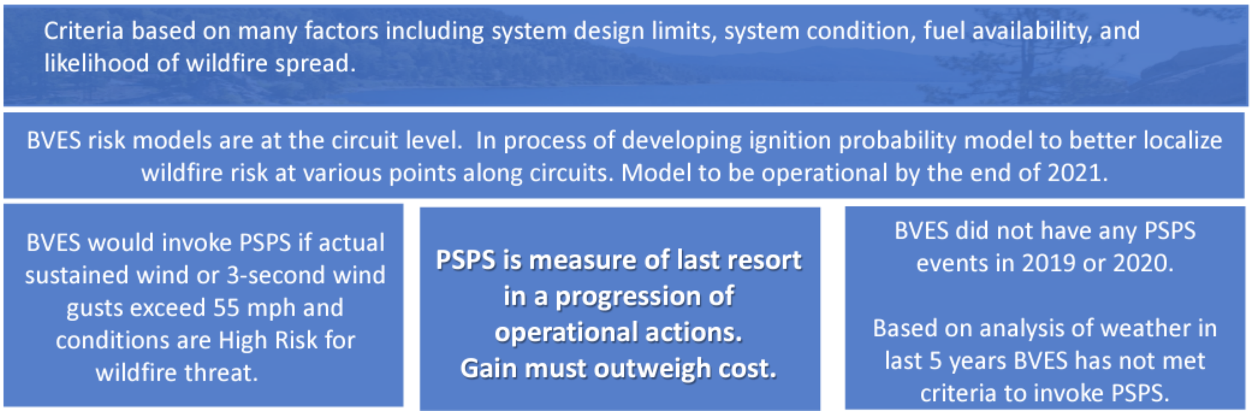
The CRC protocols are as follows:

During a PSPS event, Bear Valley Electric Service, Inc. will set up a CRC at its Main Facility at 42020 Garstin Dr., Big Bear Lake, CA 92315 adjacent to the Warehouse. The Customer Service and Operations Support Supervisor shall be responsible for ensuring these protocols are properly implemented when the CRC is activated.
The CRC shall be operable from 8:00 a.m. to 10:00 p.m. during an active PSPS event. Actual hours of operation will be coordinated and determined by the local government in cases in which early closure of a facility is required due to inability to access a facility until 10:00 p.m.
They will initially be set up in the Warehouse so that quick access and set up may occur.
The setup of the CRC shall be ADA (Americans with Disabilities Act) accessible to meet the needs of people/communities with access and functional needs and medical baseline customers.
At all times the CRC shall comply with social distancing or other public health protocols that are in place.
The following supplies and equipment are stored in the CRC Storage Container to support CRC operations:
Tents (2)
Water
Snacks (such as crackers, granola bars, etc.…)
Chairs
Heaters
Extension cords
Disposable masks (as necessary)
Gloves (as necessary)
Hand sanitizer (as necessary)
Flashlights
Small first aid kits
Blankets
Surge Protectors
Gas tank
Generators
Wireless internet access point
The CRC will operate as follows:
The Customer Service and Operations Support Supervisor and Customer Program Specialist will be in charge of the CRC.
The CRC will be set up and operated by:
Field personnel/warehouse person will set up and assist as needed
Customer Service and Operations Support Supervisor
Customer Program Specialist
Security and Access will be conducted by the Customer Service Representatives and Operations Support Specialists.
Customer Service Representatives will staff an Information Booth to provide customers the latest information regarding PSPS and services available to them.
Medical Equipment Access (Generators/power supplies) will be provided for Customers who are on medical devices such as oxygen, etc.
Access to Wi-Fi and back-up cell phones (as necessary) will be provided to Customers.
Until portable restroom facilities are available, customers will have access to the Main Office restroom facilities.

Outline of tactical and strategic decision-making protocol for initiating a PSPS/de-energization (e.g., decision tree).

Section 5 of the attached PSPS Plan outlines the PSPS protocols, which includes the tactical and strategic decision for initiating a PSPS/de-energization. Section 4 describes the conditions that could lead to a PSPS enactment, and Section 2 describes the chain of command for initiating a PSPS event.

Figure 8.2-4: PSPS Decision-Making Criteria



In summary, BVES considers the following when determining conditions that would meet or exceed thresholds for de-energization:

Design strength and other characteristics of distribution overhead facilities,
Vegetation density,
NFDRS for 7-day fire threat outlook,
NWS advisories,
Local weather forecasts and advisories,
BVES meteorologist's forecast,
Information from BVES installed weather stations,
Real-time information from trained personnel positioned in high-risk areas, and
Input from state and local authorities and Emergency Management Personnel.

"Extreme fire weather conditions" are deemed to be forecasted or exist when the NFDRS forecast is "red," "orange," or "brown", high winds (45 mph or greater) are forecasted or measured, and the BVES meteorologist forecasts high fire threat conditions. Once it is determined that "extreme fire weather conditions" are forecasted or exist, BVES Staff will implement BVES PSPS Procedures at the direction of the Utility Manager.

Table 8.2-2: PSPS Activation Phases Before and During an Event

PSPS Activity	Phase Event	Internal Action	External Coordination
Warning	**4-7 Days Ahead** (Forecasts indicate extreme fire threat weather and conditions may occur)	**Operations & Planning:** Evaluate possible impacted area(s) and ensure resources ready to support PSPS. Contact SCE Staff and maintain status of SCE supply lines.	None

PSPS Activity	Phase Event	Internal Action	External Coordination
		Review operational and maintenance status of sub-transmission system. Review operational and maintenance status of Bear Valley Power Plant (BVPP). Review operational and maintenance status of Radford Line. Consider conducting patrol of Radford Line. Review National Weather Service (NWS) forecasts, National Fire Danger Rating System (NFDRS) 7-day forecast, and weather and threat assessments from contracted meteorology consultant. Consider having meteorology consultant provide more frequent forecasts. Alert customer service to possibility of PSPS. **Customer Service and Energy Resources:** Review and edit as applicable templates for PSPS events and the anticipated impacts on BVES Customers. Staff drafts notices to Public Affairs consultant for review, significant changes to templates are made. Create warning notifications to customers via email, telephone calls, IVR proactive calling system, and two-way text messaging. Ensure Stakeholders' Portal is ready for use.	
Warning	**4 Days Ahead** (Continuing and consistent forecasts of	**Operations & Planning:** Closely monitor fire weather alerts from various sources with the goal of refining the	**Local Government, Agencies, and Partner Organizations:**

PSPS Activity	Phase Event	Internal Action	External Coordination
	extreme fire threat weather and conditions)	forecast (NWS, NFDRS, and meteorology consultant weather and threat assessments). Contact SCE Staff and maintain status of SCE supply lines. If any SCE lines are under "PSPS Consideration," take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Consideration. Ensure sub-transmission system is in most reliable condition. Defer and/or secure from planned maintenance. Ensure BVPP ready to operate. Defer and/or secure from planned maintenance. Alert Energy Resource Department of possible extended BVPP operations. Consider energizing Radford Line, if deemed necessary for reliability. Closely coordinate with SCE Staff regarding the PSPS status of SCE supply lines (Doble, Cushenberry, and Bear Valley/Radford). Ensure BVES installed weather stations fully operational. Ensure circuit load monitoring equipment fully operational. Place BVES staff incident responders on alert. **Customer Service:** Finalize "4 Day Alert" email regarding continuing and consistent forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Also, provide anticipated impacts on BVES Customers and direction of event. Obtain	Email "4 Day Alert" to local government, agencies, and partner organizations primary and secondary points of contact. Alert the emergency management community, first responders and local government first. Update Stakeholders' Portal. Remind stakeholders of Portal.

PSPS Activity	Phase Event	Internal Action	External Coordination
		President's approval to release. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging. Update Stakeholders Portal	
Warning	**2-3 Days Ahead** (Extreme fire threat weather and conditions forecasted with increasing confidence)	**Operations & Planning:** Continue to closely monitor fire weather alerts from various sources with the goal of refining the forecast (NWS, NFDRS, and meteorology consultant weather and threat assessments). Prepare staff rotation plans to support continuous field crew operations, BVPP operations, dispatch, and customer service. Evaluate need for additional resources from mutual aid agreements (CUEA and MMAA) and contracted services. Alert additional resources points of contact. Set up processes to frequently monitor BVES installed weather stations. Review pre-approved field Switching Orders against current system line-up and make changes as applicable with Field Operations Supervisor's approval. Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. Closely coordinate with SCE Staff regarding SCE supply	**Local Government, Agencies, and Partner Organizations:** Email "2-3 Day Notice" to local government, agencies, and partner organizations primary and secondary points of contact. Coordinate with the emergency management community, first responders and local government first. Encourage widest dissemination of this information Update Stakeholders' Portal **Customer Outreach:** Post "2-3 Day Notice" on BVES website and social media. Issue "2-3 Day Notice" press release for local media. Send out "2-3 Day Notice" via IVR. Send out "2-3 Day Notice" via Text

PSPS Activity	Phase Event	Internal Action	External Coordination
		lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. **Customer Service:** Finalize "2-3-Day Notice" regarding forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts on BVES Customers and direction of event. Obtain President's approval to release. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging. Update Stakeholders Portal Simultaneously notifies the CPUC via email and the CSWC via the Online PSPS State Notification Form Notifies local safety partners Develops impact list and scopes impacted customers Initiates State Executive Conference Calls and operational briefings throughout the event Designates 24-hour point of contact for receiving parties	Send out "2-3 day Notice" via email Update Stakeholders Portal
Warning	**1-2 Days Ahead** (Extreme fire threat weather and conditions forecasted with	**Operations & Planning:** Continue to closely monitor fire weather alerts from various sources with the goal of refining the forecast (NWS,	**Local Government, Agencies, and Partner Organizations:** Email "1-2 Day Notice" to local government,

PSPS Activity	Phase Event	Internal Action	External Coordination
	high degree of confidence)	NFDRS, and meteorology consultant weather and threat assessments). If needed, request additional resources from mutual aid agreements (CUEA and MMAA) and contracted services). Monitor BVES installed weather stations on a frequent basis. Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. Set up CRC and conduct a mock SOE scenario to include testing of all equipment and needed supplies. Purchase non-perishable food items to provide to our customers including bottled water. Continue to closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. When directed by the Utility Manager: Staff incident responders called in. Incident dispatch established. Field Crews dispatched to monitor various actual field conditions for extreme fire weather and other dangerous conditions throughout the service area and "at risk" areas.	agencies, and partner organizations primary and secondary points of contact. Coordinate with the emergency management community, first responders and local government first. Encourage widest dissemination of this information. Update Stakeholders Portal **Customer Outreach:** Post "1-2 Day Notice" on BVES website and social media. Issue "1-2 Day Notice" press release for local media. Send out "1-2 Day Notice" via IVR. Send out "1-2 Day Notice" via Text Activate "1-2 day Notice" via email

PSPS Activity	Phase Event	Internal Action	External Coordination
		Implement BVES ERP including staffing the EOC as applicable. **Customer Service:** Finalize "1-2 Day Notice" regarding imminent extreme fire threat weather and conditions, which may result in BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts on BVES Customers and duration of event. Obtain President's approval to release. Update list of medical baseline customers that may lose power as result of PSPS. Update list of AFN customers that may lose power as result of PSPS. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging Update Stakeholders Portal	
Warning	**1-4 Hours Ahead** When De-Energization Imminent. (Extreme fire threat weather and conditions validated by field resources)	**Operations & Planning:** Closely coordinate with SCE regarding SCE directed PSPS that affect SCE lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. Field Operations staff frequently monitor BVES installed weather stations. Field Crews patrol throughout service area and the "at risk" areas to monitor various actual field conditions for extreme fire	**Local Government, Agencies, and Partner Organizations:** Email "De-energization Imminent Notice" to local government, agencies, and partner organizations. Coordinate with the emergency management community, first responders, and local government in

PSPS Activity	Phase Event	Internal Action	External Coordination
		weather and other dangerous conditions. Field Crews monitor local wind gusts in "at-risk" areas. **Customer Service:** Finalize "De-energization Imminent Notice" regarding extreme fire threat weather and conditions validated by field resources and actual PSPS de-energization(s) directed by BVES and/or SCE and includes areas de-energized, number of customers without power, and best estimated time to restore (ETR). Obtain President's approval to release. Refine lists of medical baseline customers without power. Update list of AFN customers that may lose power as result of PSPS BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging. Update Stakeholders Portal	managing outages due to PSPS. Provide list of customers that may be without power and listed as medical baseline customers to Sheriff Department and Fire Department. Encourage widest dissemination of this information. **Customer Outreach:** Post "De-energization Imminent Notice" on BVES website and social media. Issue "De-energization Imminent" press releases for local media. Send out "De-energization Imminent Notice" via IVR. Send out "De-energization Imminent Notice Day Notice" via Text Send out "De-energization Imminent Notice" via email
Implementation	**During de-energization event.** (Extreme fire threat weather and conditions validated by field resources)	**Operations & Planning:** Closely coordinate with SCE regarding SCE directed PSPS that affect SCE lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. Field Operations staff frequently monitor BVES installed weather stations. Field Crews patrol throughout service area and the "at risk"	**Local Government, Agencies, and Partner Organizations:** Email "De-energization Notice" to local government, agencies, and partner organizations. Update Stakeholders Portal Coordinate with the emergency management

PSPS Activity	Phase Event	Internal Action	External Coordination
		areas to monitor various actual field conditions for extreme fire weather and other dangerous conditions. Field Crews monitor local wind gusts in "at-risk" areas. Field Crews de-energize circuits in "at risk" areas as wind gusts reach threshold for de-energization as designated by Field Operations Supervisor. Field Crews may de-energize additional power lines they evaluate as posing a public safety hazard and/or as directed by Field Operations Supervisor. Prepare GO-166 major outage and ESRB-8 notifications as applicable. **Customer Service:** Finalize "De-energization Notice" regarding extreme fire threat weather and conditions validated by field resources and actual PSPS de-energization(s) directed by BVES and/or SCE and includes areas de-energized, number of customers without power, and best estimated time to restore (ETR). Obtain President's approval to release. Finalize "De-energization Updates" providing status changes such as when the number of customers without power and/or ETR(s) change significantly. Obtain President's approval to release. Refine lists of medical baseline customers without power.ES will issue a press release to local media (newspaper and radio) and will post notification on website.	community, first responders, and local government in managing outages due to PSPS. Send "De-energization Updates" on the PSPS. Provide list of customers without power and listed as medical baseline and AFN customers to Sheriff Department and Fire Department. Encourage widest dissemination of this information. Notify California Public Utilities Commission (CPUC) and Warning Center at the Office of Emergency Services San Bernardino within one hour of shutting off the power if the outage meets the major outage criteria of GO-166. Notify President Safety Enforcement Division (SED), CPUC within twelve hours of the power being Shutoff per ESRB-8. **Customer Outreach:** Post "De-energization Notice" and "De-energization Updates" (when warranted) on BVES website and social media. Issue "De-energization Notice" and "De-energization Updates" (when warranted) press releases for local media.

PSPS Activity	Phase Event	Internal Action	External Coordination
		Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging. Update Stakeholders Portal	Send out "De-energization Notice" and "De-energization Updates" (when warranted) via IVR. Send out "De-energization Notice" and "De-energization Updates" (when warranted) via Text Activate "De-energization Notice" and "De-energization Updates" (when warranted) via email Communicate with emergency services regarding AFN and medical baseline customers.

Strategy to provide for safe and effective re-energization of any area that was de-energized due to PSPS protocol

Section 4.9 of BVES's PSPS Plan describes the internal strategy to safely re-energize any area that was de-energized as part of a PSPS event. Restoration may take place when wind speeds in the affected area where PSPS was invoked calm down below 50 mph for a minimum period of 20 minutes, and crews assess that the fire weather conditions have subsided to "safe levels." However, the crews may extend the calm period beyond 20 minutes, if they assess that further gusts of greater than 50 mph are likely based on their direct observation of local conditions or forecasts indicate a high probability of winds picking up to greater than 50 mph. Crews are to communicate with the Field Operations Supervisor prior to assessing the situation as "safe levels" so that an evaluation of actual conditions in the field may be merged with the latest forecasted information.

Restoration activities include: 1) validating that the extreme fire weather conditions have subsided to safe levels, 2) conducting field inspections and patrols of facilities that were de-energized, and 3) re-energization of inspected (and repaired if necessary) circuits. See the table below for additional detail.

Table 8.2-3: PSPS Re-energization and Post Event Strategy

PSPS Activity	Phase Event	Internal Action	External Coordination
Restoration	**Re-energization** (Extreme fire conditions subside to	**Operations & Planning:** Field Crews validate that the extreme fire weather conditions have subsided to safe levels as designated	**Local Government, Agencies, and Partner Organizations:** Send "Intent to Restore" notice to local government, agencies, and partner organizations.

PSPS Activity	Phase Event	Internal Action	External Coordination
	safe levels as validated by field conditions)	by the Field Operations Supervisor and report these conditions to Dispatch. Field Crews conduct field inspections and patrols of facilities that were de-energized. When field inspections and patrols are completed satisfactorily, power is restored to the affected circuits. As SCE restores supply lines, Field Crews conduct switching operations as directed by Field Operations Supervisor to restore systems normal. **Customer Service:** Finalize "Intent to Restore" notice to include ETR(s) and obtain President's approval to release. Finalize "Restoration Complete" notice to be issued when power is fully restored and obtain President's approval to release. Breakdown of CRC including removal/storage of all equipment and supplies Prepare post-event reports Update Stakeholders Portal	Encourage widest dissemination of this information. Coordinate with the emergency management community, first responders, and local government in managing restorations. Send "Restoration Complete" notice to local government, agencies, and partner organizations once power is fully restored or an update if restoration is delayed. Update Stakeholders Portal **Customer Outreach:** Post "Intent to Restore" notice on BVES website and social media. Issue "Intent to Restore" press release for local media. Send out "Intent to Restore" notice via IVR. Send out "Intent to Restore" notice via Text Send out "Intent to Restore" notice via email Post "Restoration Complete" notice on BVES website and social media once power is fully restored or an update if restoration is delayed. Issue "Restoration Complete" press release for local media once power is fully restored or an update if restoration is delayed. Send out "Restoration Complete" notice via IVR once power is fully restored or an update if restoration is delayed. Send out "Restoration Complete" notice via Text once power is fully restored or an update if restoration is delayed.

PSPS Activity	Phase Event	Internal Action	External Coordination
			Send out "Restoration Complete" notice via email once power is fully restored or an update if restoration is delayed.
Reporting and Lessons Learned	**Post Event**	**Operations & Planning:** Utility Manager conduct lessons learned with applicable staff. Include Customer Service and solicit input from Local Government, Agencies, and Partner Organizations. If applicable, update plan and procedures per the lessons learned. Prepare PSPS Post Event Report required by ESRB-8 and forward to President and Manager Regulatory Affairs for approval.	**CPUC Safety Enforcement Division:** File a report (written) to President of SED no later than 10 business days after the Shutoff event ends per ESRB-8.

Company standards relative to customer communications, including consideration for the need to notify priority essential services – critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies. This section, or an appendix to this section, must include a complete listing of which entities the electrical corporation considers to be priority essential services. This section must also include a description of strategy and protocols to ensure timely notifications to customers, including access and functional needs populations, in the languages prevalent within the utility's service territory.

See Table 6-1 of the BVES PSPS Plan for a comprehensive template outlining the communications plan for notifying the public and key partners during a potential PSPS activation. **Table 8.2-2** also depicts the communication stream and phased notice procedures for affected parties. Developing communication and notification procedures must be a coordinated effort across public safety partners and local jurisdictions. BVES understands it is ultimately responsible and accountable for the safe deployment of PSPS activations and restoration activities. BVES has coordinated with emergency responders, fire, and local governments to become seamlessly integrated into the communication protocols with a goal of those agencies to provide secondary notices as warranted.

Additionally, records of 2019-2021 activities are publicly displayed on BVES's website with updated correspondence relating to new and planned communication activities.[57] BVES also filed under R. 18-10-007 on December 31, 2020 its 2020 Wildfire Mitigation Community Outreach Survey Results, executed in

[57] BVES. "BVES WMP & PSPS Outreach (2019 – 2020)." https://www.bvesinc.com/media/managed/wmp/BVES_WMP_PSPS_Outreach_2019_2020.pdf.

October 2020.[58] The conducted survey was a joint effort among the SMJUs.[59] Over the course of 2020 and 2021, BVES has gained insight into areas of refinement as part of its PSPS and communication protocols. To address these concerns, BVES plans to:

Continue to promote BVES's efforts to reduce the risk of wildfire, focusing especially on systems hardening, including inspections, covered conductors, wood pole alternatives, additional control devices, and weather monitoring points

Increase messaging around preparing an emergency kit, irrigation, a readiness plan, and purchasing fire extinguishers, as customers are considerably less likely to have taken these actions, relative to vegetation management

Utilize direct mail, bill inserts, email, and BVES website as the channels for communications about wildfire preparedness and safety; consider increasing BVES presence on social media to reach wider audience

Leverage TV news and social networks to educate consumers about PSPS events, and make special effort to reach those with medical conditions requiring electricity

In order to increase awareness of whether customers live/work in a PSPS area, consider adding a link to the PSPS map to the homepage and the wildfire mitigation page (in addition to the PSPS page) on the BVES website for wider access

A follow up survey was conducted in November-December of 2021 with the results and comparison to earlier survey filed under R. 18-12-005. This survey demonstrated an increased awareness of the boundaries of PSPS Areas, maps, conditions leading to a PSPS, vegetation trimming, and more when compared to the prior survey.

Accurate, effective, and timely communications with key stakeholders is critical in response to emergencies including PSPS events, and, therefore, it is essential that business and entity relationships be developed before emergency response is ever deemed necessary. BVES has worked to identify priority stakeholders and critical facilities along with identifying the appropriate contacts, their roles and responsibilities, and the entity's support capabilities and needs in the event a wildfire or PSPS incident occurs. The key stakeholders identified in addition to the AFN and vulnerable populations groups include:

Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
State officials (California Public Utilities Commission)
San Bernardino County Office of Emergency Services (County OES)
Big Bear Fire Department
California Department of Forestry and Fire Protection (CAL FIRE)
U.S. Forest Service
San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
California Highway Patrol (CHP) Arrowhead Area
California Department of Transportation (Caltrans)
Big Bear Area Regional Wastewater Agency (BBARWA)
Big Bear City Community Services District (CSD)
Big Bear Lake Water Department (DWP)
Big Bear Municipal Water District (MWD)
Southwest Gas Corporation

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[58] CPUC Docket R. 18-10-007. "Bear Valley Electric Service (U 913-E) 2020 Wildfire Mitigation Community Outreach Survey Results." https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M357/K997/357997229.PDF. December 31, 2020.

[59] D.20-03-004 required the IOUs to facilitate and file independent survey results assessing the effectiveness of their community outreach and engagement efforts before, during and after a wildfire, whether pursuant to the in-language requirements or in English, by December 31, 2020.

Bear Valley Community Hospital
Bear Valley Unified School District
Big Bear Chamber of Commerce
Big Bear Airport District
Big Bear Mountain Resort
State officials (normally CPUC Energy Division and Safety Enforcement Division)
Spectrum Communications
Various cell tower providers
Various media and communications companies

Protocols for mitigating the public safety impacts of these protocols, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water utilities/agencies.

The PSPS Plan seeks to minimize the use of PSPS due to the public safety impacts of de-energization. Section 6.4 of BVES's PSPS Plan elaborates upon what the utility identifies as critical facilities and infrastructure. BVES defines 'critical facilities' and 'critical infrastructure' as facilities and infrastructure essential to the public safety and that require additional assistance and advance planning to ensure resiliency during PSPS events. This includes the emergency services sector (i.e., police, fire, emergency operations centers), government facilities, healthcare and the public health sector, the energy sector, water/wastewater systems sector, communications sector, and chemical sector.

Additionally, BVES will perform the following activities:

Deploy wildfire Response Team(s) to high fire risk areas,
Adjust protective device settings optimized for fire prevention,
Increase frequency of consultant meteorologist forecast,
Increase monitoring of weather stations, forecasts, and fire threat conditions,
Increase communications with Southern California Edison points of contact,
Proactively engage with first responders, local government and agencies, and other stakeholders,
Proactively communicate with customers and other stakeholders,
Identify Medical Baseline customers and Access and Functional Needs populations that may be impacted,
Prepare to activate Community Resource Center,
Activation of Emergency Operations Center and Emergency Response Plan,
Prepare Bear Valley Power Plant for sustained operations,
Conduct switch operations to minimize impact of potential PSPS activity,
Engage temporary generation, and
Activate Community Resource Center.

8.3 Projected Changes to PSPS Impact

Describe organization-wide plan to reduce scale, scope, and frequency of PSPS for each of the following time periods, highlighting changes since the prior WMP report and including key program targets used to track progress over time,

1. By June 1 of current year

BVES revised its PSPS Plan on February 24, 2021, which is attached to this WMP as **Appendix B**. BVES is working to update the next version of the protocols to align with Phase 3 PSPS guidelines issued in June 2021. BVES also held a tabletop exercise of PSPS activation ahead of June 1st. Lessons learned following that exercise include the need to continue improvement of coordinated communication with external parties, increase exercise complexity, provide additional background training for certain roles, and prepare for more in-person and remote work emergencies.

2. By September 1 of current year

BVES does not anticipate a need to develop an organization-wide plan to reduce the scale, scope, and frequency of PSPS impacts by this timeframe beyond the recently adopted PSPS Plan. The current protocols outlined in the PSPS Plan and in process updates for Phase 3 are reasonable and suitable for this period. Additionlly, BVES held an awareness workshop and functional exercise on June 21, 2022, to engage public safety partners on PSPS activation potential and an overview of the PSPS plan and protocols. BVES filed its Pre-Season Report on July 1, 2022.

3. By next Annual WMP Update

BVES does not anticipate a need to develop an organization-wide plan to reduce the scale, scope, and frequency of PSPS impacts by this timeframe beyond the recently adopted PSPS Plan and the updates required as part of Phase III. The current protocols outlined in the PSPS Plan are reasonable and suitable for this period. BVES has not needed to enact a PSPS in the past and BVES has implemented numerous additional wildfire prevention strategies over that time. As BVES continues to reduce ignition risk, the need for its PSPS should become even more remote, but BVES will remain vigilant and continue to evaluate the risk and necessity for enacting a PSPS event. Additionally, BVES will monitor developments at SCE and closely coordinate, and be ready to respond to any SCE PSPS that may cut imports to BVES. Finally, BVES will endeavor to follow lessons learned across California regarding the use of PSPS and will update its PSPS Plan and Emergency Response Plan accordingly.

Additionally, BVES plans to integrate recommendations from its conducted survey outreach in 2020 and 2021. These recommendations include, but are not limited to, the following:

Increase messaging around preparing an emergency kit, irrigation, a readiness plan, and purchasing fire extinguishers, as customers are considerably less likely to have taken these actions, relative to vegetation management;

Utilize direct mail, bill inserts, email, and BVES website as the channels for communications about wildfire preparedness and safety; consider increasing BVES presence on social media to reach wider audience;

Use TV news and social networks to educate consumers about PSPS events, and make special effort to reach those with medical conditions requiring electricity; and

Consider adding a link to the PSPS map to the homepage and the wildfire mitigation page (in addition to the PSPS page) on the BVES website for wider access.

8.4 Engaging Vulnerable Communities

Report on the following:

Describe protocols for PSPS that are intended to mitigate the public safety impacts of PSPS on vulnerable, marginalized and/or at-risk communities. Describe how the utility is identifying these communities.

Section 6 of the attached PSPS Plan describes BVES's communication protocols designed to mitigate the public safety impacts of PSPS on the community. Due to the significant impact that a PSPS event may have on the community and customers, it is essential that early and accurate communications be conducted throughout the PSPS event coincides with local government, agencies, partner organizations (including emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and functional needs), and customers. BVES takes additional steps to ensure that vulnerable, marginalized, and at-risk communities are sufficiently informed of PSPS activities and wildfire outreach. As part of its public outreach, BVES is working towards increasing representation of people with AFN, senior citizen groups, business owners, and public health and healthcare providers including those with medical needs. This includes a CRC and communications regarding PSPS.

BVES, in collaboration with its contract public relations firm has also implemented new plans to further enhance its ability to engage vulnerable individuals and communities. Working with this firm, BVES will continue its prior communication methods and attempt to establish new forms to better identify and engage with its marginalized and at-risk individuals and communities. This includes issuing a bifold/postcard (or similar mailer) in both Spanish and English via mail carrier to its residents. This mailer was also made available on BVES's website in the other top identified languages of French, Tagalog, Vietnamese, and Chinese, as well as languages spoken by indigenous communities, such as Mixteco and Zapoteco. BVES also conducted a non-contact electronic survey regarding its WMP outreach and has made the results of the survey available in English and Spanish on its website. Finally, BVES has implemented and began utilizing newly acquired two-way texting capabilities to notify BVES customers about PSPS events or other emergencies.

BVES's efforts since January 1, 2021 include the following:

Increased social media posts regarding AFN education and how to self-identify

Created and uploaded an AFN informational video on BVES's social media platforms and website

Added AFN self-identification letter to the BVES website

Entered into a confidentiality agreement to share BVES's AFN and Medical Baseline population with the City of Big Bear Lake and the local fire agencies

Added additional CRC information and accommodations to the website

Implemented a PSPS portal for critical facilities and community-based organizations

Updated the AFN application to be available in English and Spanish on BVES's website

Trained customer service representatives to inquire on all calls about potentially AFN-eligible members in customer households

Purchased portable batteries for PSPS events that are reserved for Medical Baseline and AFN community members

A small number of BVES customers reside in mobile home parks or in multi-unit residences that have electric master meters. Among these customers, BVES identified five locations to include in its medical baseline tracking sheets. Since July 1, 2021, BVES has been including AFN applications in English and Spanish, CARE applications, Medical Baseline applications, and informational flyers on PSPS and its CRC for master metered property owners and their tenants.

List all languages which are "prevalent" in utility's territory. A language is prevalent if it is spoken by 1,000 or more persons in the utility's territory or if it is spoken by 5% or more of the population within a "public safety answering point" in the utility territory[60] (D.20-03-004).

The languages prevalent in BVES's service territory include English and Spanish.

List all languages for which public outreach material is available, in written or oral form.

BVES works with its contracted public relations firm to provide outreach in a number of languages, including English, Spanish, French, Tagalog, Vietnamese, and Chinese, as well as Mixteco and Zapoteco

Detail the community outreach efforts for PSPS and wildfire-related outreach. Include efforts to reach all languages prevalent in utility territory.

BVES hosts and advertises its end-of-year public meeting where WMP, PSPS, and reliability plans are presented through local radio and newspaper. BVES will ensure its website is updated and contains the current WMP and associated video. BVES also uses Facebook to regularly distribute the WMP including the WMP's identified equipment upgrades, vegetation management, and operational improvements. Finally, BVES issues newsletters that include information regarding the WMP and PSPS plans. BVES will ensure all communications and outreach portals will be maintained in English.

BVES, in collaboration with its contract public relations firm, has also implemented new plans to further enhance its ability to engage vulnerable individuals and communities. Working with this firm, BVES will continue its prior communication methods and establish new forms to endeavor to identify and engage with its marginalized and at-risk communities. This included issuing communications in both Spanish and English; as applicable, via mail carrier to its identified customers. This mailer was also made available on BVES's website in the other top identified languages of French, Tagalog, Vietnamese, and Chinese, as well as languages spoken by indigenous communities not in BVES's service territory, such as Mixteco and Zapoteco. BVES also conducted a non-contact electronic survey regarding its WMP outreach and has made the results of the survey available in English and Spanish on its website. Finally, BVES has implemented and began utilizing newly acquired two-way texting capabilities to notify BVES customers about PSPS events or other emergencies.

See example tracking reports for communications delivered throughout 2021. Additional detail is provided in BVES's 2020 and 2021 Wildfire Mitigation Community Outreach Survey Results.[61] BVES conducted two surveys in 2021, to evaluate the effectiveness of its outreach efforts. A total of 190 surveys were completed which included 23 from critical customers, between August and December 2021. A prior survey was conducted Mid-August of 2020. The results from the first 2020 survey compared to Mid-November 2021 are as follows:

17% of BVES customers surveyed in mid-August 2020 were aware if their address was in a PSPS Area, compared to 23% of those surveyed in mid-November 2021

9% of BVES customers surveyed in mid-August 2020 were aware of the PSPS Map on the BVES website, compared to 15% of those surveyed in Mid-November of 2021

76% of BVES customers surveyed mid-August 2020 were aware BVES will proactively shut off power during extreme and dangerous weather, compared to 81% of those surveyed in mid-November 2021

56% of BVES customers surveyed mid-August 2020 were aware of the factors BVES uses before initiating a PSPS, compared to 59% of those surveyed in mid-November 2021

[60] See Cal. Government Code § 53112

[61] CPUC Docket R. 18-10-007. "Bear Valley Electric Service (U 913-E) 2020 Wildfire Mitigation Community Outreach Survey Results." https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M357/K997/357997229.PDF. December 31, 2020.

51% of BVES customers surveyed mid-August 2020 were aware of the vegetation management efforts by BVES to mitigate Wildfire risk, compared to 55% of those surveyed in mid-November 2021

17% of BVES customers surveyed mid-August 2020 were aware of the UAV and ground inspections performed by BVES to help reduce fire risk, compared to 19% of those surveyed in mid-November 2021

10% of BVES customers surveyed mid-August 2020 were aware of the weather monitoring points BVES uses and shares the data with local weather and fire department, compared to 13% of those surveyed in mid-November 2021

88% of customers surveyed in mid-August have taken action to trim vegetation around their home/property, compared to 92% of those surveyed in mid-November 2021

English remains the preferred language for utility related communications

The list of community engagement activities in 2021 are presented in the table below.

Figure 8.4-1: WMP and PSPS Community Engagement Activities

Date Posted/Sent	Method Of Communication	WMP/PSPS
January 14, 2021	E-Newsletter (Winter 2020)	WMP/PSPS
June 16, 2021	Newsletter (Summer 2021)	WMP/PSPS
January 1, 6, 10, 15, 18, 20, 25, 28, 2021	KBHR	Vegetation management
January 1, 5, 14, 19, 24, 28, 2021	KBHR	WMP/PSPS (Two-way text)
January 1, 3, 8, 13, 18, 21, 27, 30, 2021	KBHR	WMP
February 1, 4, 9, 13, 18, 22, 26, 2021	KBHR	WMP
February 1, 6, 10, 15, 19, 23, 27, 2021	KBHR	WMP/PSPS (Two-way text)
February 2, 8, 13, 17, 23, 28, 2021	KBHR	Vegetation management
March 3, 5, 9, 14, 18, 23, 28, 31, 2021	KBHR	WMP
March 1, 5, 10, 14, 19, 22, 26, 29, 2021	KBHR	Vegetation management
March 2, 6, 9, 14, 18, 23, 26, 31, 2021	KBHR	WMP/PSPS (Two-way text)
April 1,3 (twice),4,5,7,8,9,10,12 (twice),14,16,17,19,21 (twice),23 (twice),25,27, 29 (twice), 2021	KBHR	Vegetation management
April 2 (twice),4, 6 (twice),9,10,11,13,14,15,16,18,19,20,22,23,24,26,27,28, 30, 2021	KBHR	WMP
April 1,3,4 (twice),5,7,8 (twice),12 (twice),14,16,17,19,21 (twice),23,25 (twice),27,29 (twice), 2021	KBHR	WMP/PSPS (Two-way text)
May 1,3 (twice),5, 7 (twice),9,11,12,15,16,19,21,23 (twice),25,27,28,30,31, 2021	KBHR	Vegetation management
May 1,3 (twice),5,7 (twice),9,11,12,15,16,19,21,23 (twice),25, 27 (twice),30,31, 2021	KBHR	WMP/PSPS (Two-way text)
May 1,2,4,5,6,8,9,10,11,13 (twice), 14, 17 (twice), 18,19,20,21,22,24,25,26,28,29,31, 2021	KBHR	WMP
June 1,3,4,5,8 (twice), 10, 12 (twice), 14,16,17,20,25,27,29,30, 2021	KBHR	Vegetation management

Date Posted/Sent	Method Of Communication	WMP/PSPS
June 18 (twice),19 (twice),20 (twice),21(twice),22 (twice),23 (twice),24 (twice), 25 (twice), 2021	KBHR	PSPS
June 2 (twice), 4, 6 (twice), 8, 10,11,13,14,15,18,20,21,23,24,26,27,29,30, 2021	KBHR	WMP
June 1,3,4,5,7,8,10,12 (twice),14, 16 (twice),19,20,22,25,27,28,30, 2021	KBHR	WMP/PSPS (Two-way text)
July 2, 3, 4, 6, 7, 8, 10, 11, 12, 14, 15, 18, 19, 20, 21, 24, 25, 26, 27, 28, 30, 31, 2021	KBHR	Vegetation management
July 1, 3, 4, 5, 7, 8, 9, 11, 12, 13, 15, 16, 17, 20,21, 22, 23, 24, 25, 27, 28, 29, 31, 2021	KBHR	WMP/PSPS (Two-way text)
July 2, 3, 4, 6, 7, 8, 10,11, 12, 14, 15, 16, 18, 19, 20, 22, 23, 24, 26, 27, 29, 30, 31, 2021	KBHR	WMP
July 16 (2 times) 17 (2 times) 18 (2 times) 19 (3 times), 2021	KBHR	WMP/PSPS community meeting
August 1, 3, 4, 5, 7, 9, 10, 11, 13, 14, 16, 17, 19, 20, 22, 23, 25, 26, 28, 29, 31, 2021	KBHR	Vegetation management
August 1, 2, 4, 5, 7, 8, 10, 11, 13, 14, 16, 17, 19, 20, 22, 23, 25, 26, 28, 29, 31, 2021	KBHR	WMP/PSPS (Two-way text)
August 2, 3, 4, 6, 7, 9, 10,12, 13, 15, 16, 18, 19, 21, 22, 24, 25, 27, 28, 30, 31, 2021	KBHR	WMP
August 5, 6 (2 times) 8, 11, 13, 14, 16, 17, 19, 20, 22, 23, 25, 26, 28, 29, 31, 2021	KBHR	WMP (UAV)
September 1, 3, 5 (2 times) 7, 9, 10, 12, 13, 15, 16, 18, 19, 21, 22, 24, 25, 27, 28, 30, 2021	KBHR	vegetation management
September 2, 3, 4, 6, 8, 9, 11, 12, 14, 15, 17, 18, 20, 21, 23, 24, 26, 27, 29, 30, 2021	KBHR	WMP
September 1, 3, 4, 6, 7, 9, 10,12, 13, 15, 16, 18, 19, 21, 22, 24, 25, 27, 28, 30, 2021	KBHR	WMP (UAV)
September 1, 3,5 (2 times), 7,9,10,12,13,15,16,18,19,21,22,24,25,27,28,30, 2021	KBHR	WMP/PSPS (Two-way text)
October 1,3,4,6,7,9,10,12,13,15,16,18,19,21,22,24,25,27,28,30, 31, 2021	KBHR	Vegetation management
October 1,3,4,6,7,9,10,12,13,15,16,18,19,21,22,24,25,27,28,30,3 1, 2021	KBHR	WMP/PSPS (Two-way text)
October 2,3,5,6,8,9,11,12,14,15,17,18,20,21,23,24,26,27,29,30, 2021	KBHR	WMP
October 1,3,4,6,7,9,10,12,13,15,16,18,19,21,22,24,25,27,28,29, 30, 2021	KBHR	WMP (UAV)

Date Posted/Sent	Method Of Communication	WMP/PSPS
November 2,3,5,8,9,10,13,14,16,17,19,20,22,23,24,25,28 (twice), 2021	KBHR	Vegetation management
November 2,3,5,8,9,10,13,14,16,17,19,20,22,23,25,26,27,29 (twice), 2021	KBHR	WMP/PSPS (Two-way text)
November 1,2,4,6,7,9,11,12,13,15,16,18,19,21,22,24,26,27,28,30, 2021	KBHR	WMP
November 1,2,4,6,7,9,11,12,13,15,16,18,19,21,22,24,25,26,28, 2021	KBHR	WMP (UAV)
December 1 (twice),3,4,5,7,8,10,11,12,14,15,17,19,20,21,23,24,26,28,29,30,31, 2021	KBHR	Vegetation management
December 3,4,5,7,8,10,11,12,14,15,16(twice),17,19,20,21,23,24,26 (twice),29,30, 2021	KBHR	WMP/PSPS (Two-way text)
December 1,2,3,5,6,7,8,9,10,11,13,14,15,17,18,19,20,22,23 (twice),26,27,28,29,30,31, 2021	KBHR	WMP
January 20-26, 2021	Grizzly	WMP/PSPS (Two-way text)
February 4-10, 2021	Grizzly	WMP/PSPS (Two-way text)
February 25 - March 3, 2021	Grizzly	WMP/PSPS (Two-way text)
March 18-24, 2021	Grizzly	WMP/PSPS (Two-way text)
March 25-31, 2021	Grizzly	WMP
April 15-21, 2021	Grizzly	WMP/PSPS (Two-way text)
April 29 - May 5, 2021	Grizzly	WMP
June 23 - 30, 2021	Grizzly	WMP/PSPS Community meeting
July 1- July 7, 2021	Grizzly	WMP/PSPS (Two-way text)
July 8-July 14, 2021	Grizzly	WMP
July 15-July 21, 2021	Grizzly	WMP
July 22 - July 28, 2021	Grizzly	WMP/PSPS (Two-way text)
July 29 - August 4, 2021	Grizzly	WMP
August 5 - August 11, 2021	Grizzly	WMP
August 12-August 18, 2021	Grizzly	WMP
August 19 - August 25, 2021	Grizzly	PSPS Community meeting
August 26 - September 1, 2021	Grizzly	PSPS Community meeting
September 2 - September 8, 2021	Grizzly	WMP
September 9 - September 15, 2021	Grizzly	WMP/PSPS (Two-way text)
September 23- September 29, 2021	Grizzly	WMP

Date Posted/Sent	Method Of Communication	WMP/PSPS
September 30 - October 6, 2021	Grizzly	WMP
October 7 - October 13, 2021	Grizzly	Tree Trimming
October 14 - October 20, 2021	Grizzly	WMP/PSPS (Two-way text)
October 21 - October 27, 2021	Grizzly	WMP/PSPS (Two-way text)
November 10 - November 16, 2021	Grizzly	Tree Trimming
November 24 - November 30, 2021	Grizzly	WMP/PSPS (Two-way text)
December 1 - December 7, 2021	Grizzly	Tree Trimming
December 8 - December 14, 2021	Grizzly	WMP/PSPS (Two-way text)
December 29, 30,31 2021	Grizzly	PSPS
January 26, 2021	Website	CA Wildfire test survey
January 26, 2021	Website	Added updated Languages WMP-PSPS
June 25, 2021	Website	PSPS
August 2, 2021	Website	PSPS Content update
September 24, 2021	Website	PSPS private page set up
October 7, 2021	Website /CRC added	PSPS
October 19, 2021	Website	PSPS page updates and edits
October 21, 2021	Website	PSPS page update communication
October 27, 2021	Website	Updates on PSPS page
November 1, 2021	Website	Updates on PSPS page
January 14,20,21,22, 2021	Facebook	Two-way Emergency text Communications post
February 17, 25, 2021	Facebook	PSPS
March 2, 16, 2021	Facebook	WMP educational post
March 4, 11,18, 2021	Facebook	PSPS educational post
April 5, 2021	Facebook	WMP educational post
April 15, 23, 2021	Facebook	Two-way Emergency Text communication post
April 23, 2021	Facebook	PSPS educational post
April 30, 2021	Facebook	PSPS educational video
May 12, 2021	Facebook	PSPS educational video
May 25, 2021	Facebook	WMP
June 1, 2021	Facebook	PSPS educational video
June 8, 2021	Facebook	PSPS
June 16, 2021	Facebook	WMP
June 21, 24, 2021	Facebook	PSPS Meeting
June 22, 2021	Facebook	PSPS

Date Posted/Sent	Method Of Communication	WMP/PSPS
July 6, 2021	Facebook	PSPS
July 7, 22, 28, 2021	Facebook	WMP
August 6, 2021	Facebook	WMP
August 10, 11, 2021	Facebook	PSPS
July 6, 7,15, 16, 2021	Facebook	PSPS
July 20, 22, 2021	Facebook	PSPS Meeting
July 23,26,28,29, 2021	Facebook	PSPS
August 3,5,10,11,12,14,19,24,26, 2021	Facebook	PSPS
September 14,17,21,28, 2021	Facebook	PSPS
October 2,12,28, 2021	Facebook	PSPS
November 16,19,23, 2021	Facebook	PSPS
December 3,9,22, 2021	Facebook	PSPS
October 4,6,7,8,11,18,25, 2021	Facebook	WMP
November 1,5,8,15,22,29, 2021	Facebook	WMP
December 1,6,13,20, 2021	Facebook	WMP

8.5 PSPS-Specific Metrics

PSPS data reported quarterly. Placeholder tables below to be filled in based on quarterly data.

Instructions for PSPS table of Attachment 3:

In the attached spreadsheet document, report performance on the following PSPS metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.

Table 11 of Attachment 3: Recent use of PSPS and other PSPS metrics – reference only, fill out attached spreadsheet to correct prior reports

Please see the Q4 EC QDR in **Attachment A** to this WMP 2022 Update as well as in **Appendix D QDR Table 11**. The data provided in Table 11 is based on the most current information available at the time and is subject to modification resulting from additional analyses, internal outage audits and assessments, completed following submission of this 2022 WMP Update.

8.6 Identification of Frequently De-energized Circuits

Senate Bill 533 (2021) added an additional requirement to the WMPs. Pub. Util. Code Section 8386(c)(8) requires the "Identification of circuits that have frequently been de-energized[62] pursuant to a de-

[62] "Frequently de-energized circuit" has been defined in the glossary as "A circuit which has been de-energized pursuant to a de-energization event to mitigate the risk of wildfire three or more times in a calendar year."

energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines." To comply with this statutory addition, utilities are required to populate Table 8.6-1 and provide a map showing the listed frequently de-energized circuits.

Table 8.6-1: Frequently de-energized circuits

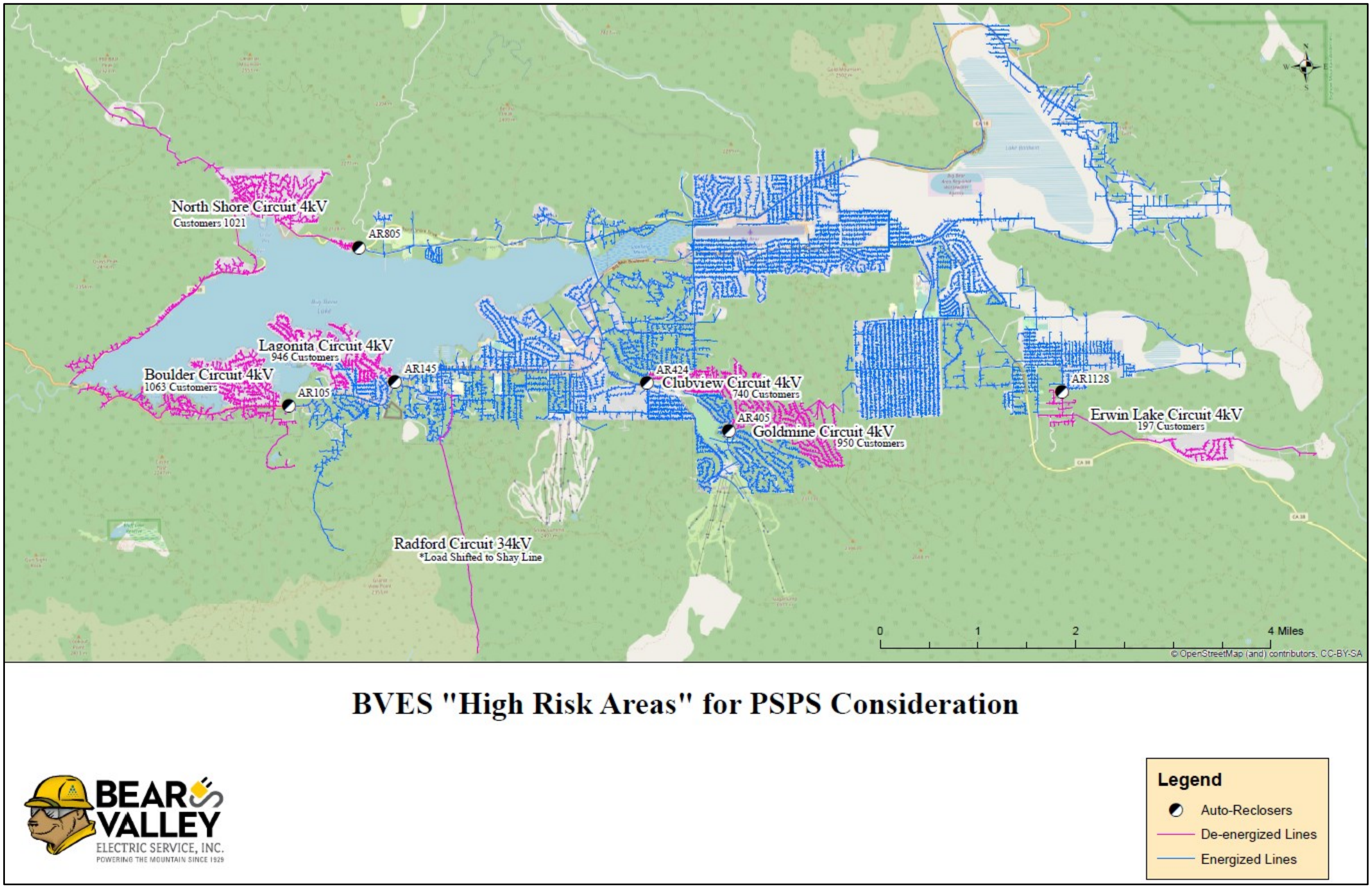
ID of Circuit	County	Dates of Outages	# of Customers Affected	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit
N/A*	N/A*	N/A*	N/A*	N/A*

(*) BVES has not reached PSPS thresholds to result in a proactive de-energization activation.

BVES has not activated any PSPS events and does not have a listing of frequently de-energized circuits. The utility has prioritized high-risk circuits for mitigation over the next ten years and does not anticipate the need to utilize the measure of last resort of initiating a proactive de-energization over time. However, there are circuits identified for de-energization in the event that PSPS triggers are met.

These circuits are identified in the figure below.

Figure 8.6-1: High Risk Areas for PSPS Consideration and Customer Count



9 APPENDIX

9.1 Definitions of Initiative Activities by Category

Table 9.1-1: Definitions of initiative activities by category

Category	Initiative Activity	Definition
A. Risk mapping and simulation	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Development and use of tools and processes to develop and update risk map and simulations and to estimate risk reduction potential of initiatives for a given portion of the grid (or more granularly, e.g., circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Climate-driven risk map and modeling based on various relevant weather scenarios	Development and use of tools and processes demonstrating medium and long-term climate trends based on the best available climate models demonstrating the most wildfire- relevant impacts (e.g., warming trends, fuel moisture trends, soil moisture trends, vegetation distribution trends). Describe how these trends are being incorporated into risk modeling or other risk-informed analyses.
	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Development and use of tools and processes to assess the risk of ignition across regions of the grid (or more granularly, e.g., circuits, spans, or assets).
	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	Development of a tool to estimate the risk reduction efficacy (for both wildfire and PSPS risk) and risk-spend efficiency of various initiatives.
	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Development and use of tools and processes to assess the impact of potential ignition and risk to communities (e.g., in terms of potential fatalities, structures burned, monetary damages, area burned, impact on air quality and greenhouse gas, or GHG, reduction goals, etc.).
B. Situational awareness and forecasting	Advanced weather monitoring and weather stations	Purchase, installation, maintenance, and operation of weather stations. Collection, recording, and analysis of weather data from weather stations and from external sources.
	Continuous monitoring sensors	Installation, maintenance, and monitoring of sensors and sensorized equipment used to monitor the condition of electric lines and equipment.
	Fault indicators for detecting faults on electric lines and equipment	Installation and maintenance of fault indicators.
	Forecast of a fire risk index, fire potential index, or similar	Index that uses a combination of weather parameters (such as wind speed, humidity, and temperature), vegetation and/or fuel conditions, and other factors to judge current fire risk and to create a forecast indicative of fire risk. A sufficiently granular index is required to inform operational decision-making.

Category	Initiative Activity	Definition
	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Personnel position within utility service territory to monitor system conditions and weather on site. Field observations is required to inform operational decisions.
	Weather forecasting and estimating impacts on electric lines and equipment	Development methodology for forecast of weather conditions relevant to utility operations, forecasting weather conditions and conducting analysis to incorporate into utility decision-making, learning and updates to reduce false positives and false negatives of forecast PSPS conditions.
C. Grid design and system hardening	Capacitor maintenance and replacement program	Remediation, adjustments, or installations of new equipment to improve or replace existing capacitor equipment.
	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	Remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.
	Covered conductor installation	Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a “suitable protective covering” (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.
	Covered conductor maintenance	Remediation and adjustments to installed covered or insulated conductors. In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non- conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.
	Crossarm maintenance, repair, and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing crossarms, defined as horizontal support attached to poles or structures generally at right angles to the conductor supported in accordance with GO 95.

Category	Initiative Activity	Definition
	Distribution pole replacement and reinforcement, including with composite poles	Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.
	Expulsion fuse replacement	Installations of new and CAL FIRE-approved power fuses to replace existing expulsion fuse equipment.
	Grid topology improvements to mitigate or reduce PSPS events	Plan to support and actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected, such as installation and operation of electrical equipment to sectionalize or island portions of the grid, microgrids, or local generation.
	Installation of system automation equipment	Installation of electric equipment that increases the ability of the utility to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).
	Maintenance, repair, and replacement of connectors, including hotline clamps	Remediation, adjustments, or installations of new equipment to improve or replace existing connector equipment, such as hotline clamps.
	Mitigation of impact on customers and other residents affected during PSPS event	Actions taken to improve access to electricity for customers and other residents during PSPS events, such as installation and operation of local generation equipment (at the community, household, or other level).
	Other corrective action	Other maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely, including remediation activities (such as insulator washing) of other electric equipment deficiencies that may increase ignition probability due to potential equipment failure or other drivers.
	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Actions taken to remediate, adjust, or install replacement equipment for poles that the utility has identified as failing to meet safety factor requirements in accordance with GO 95 or additional utility standards in the utility's pole loading assessment program.
	Transformers maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.
	Transmission tower maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65kV).
	Undergrounding of electric lines and/or equipment	Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).
	Updates to grid topology to minimize risk of ignition in HFTDs	Changes in the plan, installation, construction, removal, and/or undergrounding to minimize the risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.

Category	Initiative Activity	Definition
D. Asset management and inspections	Detailed inspections of distribution electric lines and equipment	In accordance with GO 165, careful visual inspections of overhead electric distribution lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Detailed inspections of transmission electric lines and equipment	Careful visual inspections of overhead electric transmission lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	Infrared inspections of distribution electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Infrared inspections of transmission electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Intrusive pole inspections	In accordance with GO 165, intrusive inspections involve movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.
	LiDAR inspections of distribution electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	LiDAR inspections of transmission electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric transmission lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric distribution lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.

Category	Initiative Activity	Definition
	Patrol inspections of distribution electric lines and equipment	In accordance with GO 165, simple visual inspections of overhead electric distribution lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of transmission electric lines and equipment	Simple visual inspections of overhead electric transmission lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Pole loading assessment program to determine safety factor	Calculations to determine whether a pole meets pole loading safety factor requirements of GO 95, including planning and information collection needed to support said calculations. Calculations must consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys, per D.15-11-021.
	Quality assurance / quality control of inspections	Establishment and function of audit process to manage and confirm work completed by employees or contractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
	Substation inspections	In accordance with GO 175, inspection of substations performed by qualified persons and according to the frequency established by the utility, including record-keeping.
E. Vegetation management and inspection	Additional efforts to manage community and environmental impacts	Plan and execution of strategy to mitigate negative impacts from utility vegetation management to local communities and the environment, such as coordination with communities, local governments, and agencies to plan and execute vegetation management work.
	Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment	Careful visual inspections and maintenance of vegetation around the distribution right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded. Describe the frequency of inspection and maintenance programs.
	Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment	Careful visual inspections and maintenance of vegetation around the transmission right-of- way, where individual trees are carefully examined, visually, and the condition of each rated and recorded. Describe the frequency of inspection and maintenance programs.
	Emergency response vegetation management due to red flag warning or other urgent weather conditions	Plan and execution of vegetation management activities, such as trimming or removal, executed based upon and in advance of forecast weather conditions that indicate high fire threat in terms of ignition probability and wildfire consequence.
	Fuel management and, management of all wood and “slash” from vegetation management activities	Plan and execution of fuel management activities in proximity to potential sources of ignition. This includes pole clearing per PRC 4292 and reduction or adjustment of live fuel (based on species or otherwise) and of dead fuel, including all downed wood and “slash” generated from vegetation management activities.

Category	Initiative Activity	Definition
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	Remote sensing inspections of vegetation around distribution electric lines and equipment	Inspections of right-of-way using remote sensing methods such as LiDAR, satellite imagery, and UAV.
	Remote sensing inspections of vegetation around transmission electric lines and equipment	Inspections of right-of-way using remote sensing methods such as LiDAR, satellite imagery, and UAV.
	Other discretionary inspections of vegetation around distribution electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Other discretionary inspections of vegetation around transmission electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Patrol inspections of vegetation around distribution electric lines and equipment	Visual inspections of vegetation along rights-of- way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of vegetation around transmission electric lines and equipment	Visual inspections of vegetation along rights-of- way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Quality assurance / quality control of vegetation management	Establishment and function of audit process to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This includes identification of the percentage of vegetation inspections that are audited annually, as a program target in Table 5.3-1.
	Recruiting and training of vegetation management personnel	Programs to ensure that the utility can identify and hire qualified vegetation management personnel and to ensure that both employees and contractors tasked with vegetation management responsibilities are adequately trained to perform vegetation management work, according to the utility's wildfire mitigation plan, in addition to rules and regulations for safety. Include discussion of continuous improvement of training programs and personnel qualifications.
	Identification and remediation of “at-risk species”	Specific actions, not otherwise described in other WMP initiatives, taken to reduce the ignition probability and wildfire consequence attributable to “at-risk species”, such as trimming, removal, and replacement.

Category	Initiative Activity	Definition
	Removal and remediation of trees with strike potential to electric lines and equipment	Actions taken to identify, remove, or otherwise remediate trees that pose a high risk of failure or fracture that could potentially strike electrical equipment.
	Substation inspection	Inspection of vegetation surrounding substations, performed by qualified persons and according to the frequency established by the utility, including record-keeping.
	Substation vegetation management	Based on location and risk to substation equipment only, actions taken to reduce the ignition probability and wildfire consequence attributable to contact from vegetation to substation equipment.
	Vegetation management enterprise system	Inputs, operation, and support for a centralized vegetation management enterprise system updated based upon inspection results and management activities such as trimming and removal of vegetation.
	Vegetation management to achieve clearances around electric lines and equipment	Actions taken to ensure that vegetation does not encroach upon the minimum clearances set forth in Table 1 of GO 95, measured between line conductors and vegetation, such as trimming adjacent or overhanging tree limbs.
	Vegetation management activities post-fire	Vegetation management (VM) activities during post-fire service restoration including, but not limited to: activities or protocols that differentiate post-fire VM from programs described in other WMP initiatives; supporting documentation for the tool and/or standard the utility uses to assesses the risk presented by vegetation post-fire; and how the utility includes fire-specific damage attributes into its assessment tool/standard.
F. Grid operations and protocols	Automatic recloser operations	Designing and executing protocols to deactivate automatic reclosers based on local conditions for ignition probability and wildfire consequence.
	Protective equipment and device settings	The utility's procedures for adjusting the sensitivity of grid elements to reduce wildfire risk, other than automatic reclosers (such as circuit breakers, switches, etc.). For example, PG&E's Fast Trip Settings.
	Crew-accompanying ignition prevention and suppression resources and services	Those firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, and water) that are deployed with construction crews and other electric workers to provide site-specific fire prevention and ignition mitigation during on-site work.
	Personnel work procedures and training in conditions of elevated fire risk	Work activity guidelines that designate what type of work can be performed during operating conditions of different levels of wildfire risk. Training for personnel on these guidelines and the procedures they prescribe, from normal operating procedures to increased mitigation measures to constraints on work performed.
	Protocols for PSPS re-energization	Designing and executing procedures that accelerate the restoration of electric service in areas that are de-energized, while maintaining safety and reliability standards.
	PSPS events and mitigation of PSPS impacts	Designing, executing, and improving upon protocols to conduct PSPS events, including development of advanced methodologies to determine when to use PSPS, and to mitigate the impact of PSPS events on affected customers and local residents.

Category	Initiative Activity	Definition
	Stationed and on-call ignition prevention and suppression resources and services	Firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, firefighting foam, chemical extinguishing agent, and water) stationed at utility facilities and/or standing by to respond to calls for fire suppression assistance.
G. Data governance	Centralized repository for data	Designing, maintaining, hosting, and upgrading a platform that supports storage, processing, and utilization of all utility proprietary data and data compiled by the utility from other sources.
	Collaborative research on utility ignition and/or wildfire	Developing and executing research work on utility ignition and/or wildfire topics in collaboration with other non-utility partners, such as academic institutions and research groups, to include data sharing and funding as applicable.
	Documentation and disclosure of wildfire-related data and algorithms	Design and execution of processes to document and disclose wildfire-related data and algorithms to accord with rules and regulations, including use of scenarios for forecasting and stress testing.
	Tracking and analysis of near miss data	Tools and procedures to monitor, record, and conduct analysis of data on near miss events.
H. Resource allocation methodology	Allocation methodology development and application	Development of prioritization methodology for human and financial resources, including application of said methodology to utility decision-making.
	Risk reduction scenario development and analysis	Development of modeling capabilities for different risk reduction scenarios based on wildfire mitigation initiative implementation; analysis and application to utility decision- making.
	Risk spend efficiency (RSE) analysis	Tools, procedures, and expertise to support analysis of wildfire mitigation initiative risk- spend efficiency, in terms of MAVF and/ or MARS methodologies.
I. Emergency planning and preparedness	Adequate and trained workforce for service restoration	Actions taken to identify, hire, retain, and train qualified workforce to conduct service restoration in response to emergencies, including short-term contracting strategy and implementation.
	Community outreach, public awareness, and communications efforts	Actions to identify and contact key community stakeholders; increase public awareness of emergency planning and preparedness information; and design, translate, distribute, and evaluate effectiveness of communications taken before, during, and after a wildfire, including Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Customer support in emergencies	Resources dedicated to customer support during emergencies, such as website pages and other digital resources, dedicated phone lines, etc.
	Disaster and emergency preparedness plan	Development of plan to deploy resources according to prioritization methodology for disaster and emergency preparedness of utility and within utility service territory (such as considerations for critical facilities and infrastructure), including strategy for collaboration with Public Safety Partners and communities.
	Preparedness and planning for service restoration	Development of plans to prepare the utility to restore service after emergencies, such as developing employee and staff trainings, and to conduct inspections and remediation necessary to re-energize lines and restore service to customers.
	Protocols in place to learn from wildfire events	Tools and procedures to monitor effectiveness of strategy and actions taken to prepare for emergencies and of strategy and actions taken during and after emergencies, including based on an accounting of the outcomes of wildfire events.

Category	Initiative Activity	Definition
J. Stakeholder cooperation and community engagement	Community engagement	Strategy and actions taken to identify and contact key community stakeholders; increase public awareness and support of utility wildfire mitigation activity; and design, translate, distribute, and evaluate effectiveness of related communications. Includes specific strategies and actions taken to address concerns and serve needs of Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Cooperation and best practice sharing with agencies outside CA	Strategy and actions taken to engage with agencies outside of California to exchange best practices both for utility wildfire mitigation and for stakeholder cooperation to mitigate and respond to wildfires.
	Cooperation with suppression agencies	Coordination with CAL FIRE, federal fire authorities, county fire authorities, and local fire authorities to support planning and operations, including support of aerial and ground firefighting in real-time, including information- sharing, dispatch of resources, and dedicated staff.
	Forest service and fuel reduction cooperation and joint roadmap	Strategy and actions taken to engage with local, state, and federal entities responsible for or participating in forest management and fuel reduction activities; and design utility cooperation strategy and joint stakeholder roadmap (plan for coordinating stakeholder efforts for forest management and fuel reduction activities).

9.2 Citations for Relevant Statutes, Commission Directives, Proceedings, and Orders

Throughout the WMP, cite relevant state and federal statutes, Commission directives, orders, and proceedings. Place the title or tracking number of the statute in parentheses next to comment, or in the appropriate column if noted in a table. Provide in this section a brief description or summary of the relevant portion of the statute. Track citations as end-notes and order (1, 2, 3…) across sections (e.g., if section 1 has 4 citations, section 2 begins numbering at 5).

Table 9.2-1: Citations for Relevant Statutes, Directives, Orders, and Proceedings

WMP Sections	Citation	Description/Summary
All	Resolution WSD-022	OEIS Action Statement approving BVES's 2021 WMP and incorporated Progress Report requirements.
Executive Summary	Resolution WSD-011 Resolution WSD-012	Resolution implementing the requirements of Public Utilities Code Sections 8389(d)(1), (2) and (4), related to catastrophic wildfire caused by electrical corporations. Pursuant to PUC 8389(d)(3), the CPUC, after consultation with the WSD, adopted and approved a wildfire mitigation plan compliance process.
Glossary	California Code of Regulation Title 14 § 895.1	"Danger Tree" means any tree located on or adjacent to a utility right-of- way or facility that could damage utility facilities should it fall where (1) the tree leans toward the right-of-way, or (2) the tree is defective because of any cause, such as: heart or root rot, shallow roots, excavation, bad crotch, dead or with dead top, deformity, cracks or splits, or any other reason that could result in the tree or main lateral of the tree falling. See chapter VII, Hazardous Tree Identification, Powerline Fire Prevention Field Guide -1977, A joint Publication of the California Department of Forestry, U.S. Forest Service, and U.S. Bureau of Land Management.
1.0	R.18-10-007 D. 19-12-039	Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018). Golden State Water Company to transfer its Bear Valley Electric Service Division to a separate sister corporation to be titled Bear Valley Electric Service, Inc
4.2	R.20-07-013 D. 19-08-27 D.14-02-015 D.18-12-014 D.19-04-020 General Order 95 General Order 166	Order Instituting Rulemaking to Further Develop a Risk-based Decision-making Framework for Electric and Gas Utilities Decision resolving 2018 General Rate Case application for Golden State Water Company, on behalf of its Bear Valley Electric Service Division CPUC Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electric Utility Facilities and Aerial Communication Facilities; Requires annual reportable ignitions through the CPUC's Fire Incident Data collection process CPUC Phase 2 Decision Adopting Safety Model Assessment

WMP Sections	Citation	Description/Summary
		Proceeding Settlement Agreement with Modifications Voluntary Agreement on a Risk-Based Decision-Making Framework Between the SED and the SMJUs in their GRCs. Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming Standards for Operation, Reliability, and Safety During Emergencies and Disasters
4.5.1	General Order 95 General Order 165 General Order 174	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service
4.5.2	General Order 165	Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting
4.6	Resolution WSD-022	OEIS Action Statement approving BVES's 2021 WMP and incorporated Progress Report requirements.
5.2	Public Utilities Code § 8386(c)(8); SB 533	SB 533, signed in 2021, amended Section 8386 to require updates to identify circuits with frequent wildfire mitigation related de-energizations and the measures to reduce the need for and impact of proactive de-energization.
5.3	Public Utilities Code § 8386(c)(8); SB 533	SB 533, signed in 2021, amended Section 8386 to require updates to identify circuits with frequent wildfire mitigation related de-energizations and the measures to reduce the need for and impact of proactive de-energization
5.4	General Order 95 Public Resources Code § 4293	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm arm (within the State

WMP Sections	Citation	Description/Summary
		Responsibility Area).
5.4.1	General Order 128	Underground electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers clearance and depths
5.4.3	General Order 165 General Order 174 General Order 128	Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service Underground electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers clearance and depths
5.4.4	General Order 165 General Order 174	Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service
6	Resolution WSD-012	Pursuant to PUC 8389(d)(3), the CPUC, after consultation with the WSD, adopted and approved a wildfire mitigation plan compliance process.
7.1	R.18-10-007 General Order 165 R.18-12-005 D. 21-06-034	Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018). Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions. Decision adopting Phase 3 revised and additional guidelines and rules for Public Safety Power Shutoffs (Proactive De-Energizations) of electric facilities to mitigate wildfire risk caused by utility infrastructure
7.2	Resolution WSD-022	Ratifying Action of the Office of Energy Infrastructure Safety on Bear Valley Electric Service, Inc.'s 2021 Wildfire Mitigation Plan Update Pursuant to Public Utilities Code Section 8386

WMP Sections	Citation	Description/Summary
7.3.2	R.18-12-005 WSD GIS Data Standards Public Resources Code § 4292 General Order 131-D R.18-03-011 D.19-07-015	Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions. Wildfire Safety Division Draft Geographic Information System Data Reporting Requirements and Schema for California Electrical Corporations (August 21, 2020); Sets forth requirements for WMP spatial data submissions CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area). CPUC Rules relating to the planning and construction of electric operation, transmission/power/distribution line facilities and substations located in California Order Instituting Rulemaking Regarding Emergency Disaster Relief Program. CPUC Decision Adopting an Emergency Disaster Relief Program for Electric, Natural Gas, Water, and Sewer Utility Customers
7.3.3	General Order 95 General Order 174 General Order 128	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service Underground electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers clearance and depths
7.3.4	General Order 95 General Order 174 General Order 165	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting
7.3.5	General Order 95 General Order 174 General Order 165 Public	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service Inspection requirements for transmission and distribution

WMP Sections	Citation	Description/Summary
	Resources Code § 4292	facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area).
7.3.9	General Order 166	Standards for Operation, Reliability, and Safety During Emergencies and Disasters
7.3.10	General Order 166	Standards for Operation, Reliability, and Safety During Emergencies and Disasters
8	R.18-12-005 R.18-03-011 D.19-07-015 D.19-05-042 D.20-05-051	Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions. Order Instituting Rulemaking Regarding Emergency Disaster Relief Program. CPUC Decision Adopting an Emergency Disaster Relief Program for Electric, Natural Gas, Water, and Sewer Utility Customers CPUC Decision Adopting De-Energization (Public Safety Power Shutoff) Guidelines (Phase 1 Guidelines) CPUC Decision Adopting Phase 2 Updated and Additional Guidelines for De-Energization of Electric Facilities to Mitigate Wildfire Risk
8.1	D. 21-06-034	Decision adopting Phase 3 revised and additional guidelines and rules for Public Safety Power Shutoffs (Proactive De-Energizations) of electric facilities to mitigate wildfire risk caused by utility infrastructure
8.2	R.18-10-007 D. 21-06-034 D.20-03-004	Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018). Decision adopting Phase 3 revised and additional guidelines and rules for Public Safety Power Shutoffs (Proactive De-Energizations) of electric facilities to mitigate wildfire risk caused by utility infrastructure CPUC Decision on Community Awareness and Public Outreach Before, During, and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues
8.4	R.18-10-007 D.20-03-004	Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018). CPUC Decision on Community Awareness and Public Outreach Before, During, and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues

WMP Sections	Citation	Description/Summary
8.6	Public Utilities Code § 8386(c)(8); SB 533	SB 533, signed in 2021, amended Section 8386 to require updates to identify circuits with frequent wildfire mitigation related de-energizations and the measures to reduce the need for and impact of proactive de-energization.
9.1	General Order 128 Public Resources Code § 4292	Underground electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers clearance and depths CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area).
Appendix A	Resolution WSD-022	Ratifying Action of the Office of Energy Infrastructure Safety on Bear Valley Electric Service, Inc.'s 2021 Wildfire Mitigation Plan Update Pursuant to Public Utilities Code Section 8386

9.3 Covered Conductor Installation Reporting

In Section 7.3.3.3.3, Covered Conductor Installation, report on the following key information for covered conductor installation:

Methodology for installation and implementation

Design and design considerations (such as selection of type of covered conductor, additional hardware needed for installation, pole strengthening or replacements, etc.)

Implementation (including timeframes, prioritization, contractor and labor needs, etc.)

Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.)

Key assumptions

Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)

Any other activities relevant to the covered conductor installation

This information must be derived from utility-specific programs and supplemented by the findings of the covered conductor working group.

Overview

As described in detail in **Section 7.3.3.3**, BVES has and maintains a covered conductor installation program, maintenance of installed covered conductor is described in **Section 7.3.3.4**. BVES engages in this practice to reduce ignitions due to contact with a foreign body (typically vegetation) from energized bare wire. When BVES refers to "covered wire" it is referring the covered conductor products that it utilizes which are 394.5 AAAC Priority wire and 336.4 ACSR Southwire covered wire products.

Methodology for Installation and Implementation

BVES intends to install covered wire on all sub-transmission lines (34.5 kV). This action will result in the entire overhead 34.5 kV system in the HFTD being either underground or covered. This program will reduce the risk of sub-transmission lines contacting vegetation or other debris and causing an ignition to near zero.

This program will significantly reduce the risk of distribution lines contacting vegetation or other debris and causing an ignition. The high-risk areas are defined by high vegetation density.

Design and Design Considerations

BVES conducted pilot programs using both covered conductor replacement and wire wrap. From these pilots, BVES decided to cover all of its 4kV and 34.5 KV distribution and sub-transmission lines but does not plan on using wire wrap in the future. BVES chose not to perform any additional wire wrap projects because it does not meet BVES's specifications, specifically limits to ampacity and limited product research and testing information.

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor suppliers, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%.

These efforts include two components: (1) replacement of the bare wire with covered conductor and (2) replacement of the wood poles with fire resistant poles. The bare wire replacement portion of the project is discussed and tracked in this initiative. The pole replacement portion of the project is discussed and tracked under initiative **7.3.3.6** (Distribution pole replacement and reinforcement, including with composite poles).

Implementation

BVES plans to replace all overhead sub-transmission bare wire with covered wire over a 6-year period of execution from 2020 to 2026 covering approximately 4.3 miles per year. Additionally, BVES intends to replace all bare 4 kV distribution wire in high-risk areas within the HFTD with covered wire. This action will result in approximately 86 miles of the 4 kV distribution lines in the system in the HFTD being covered at approximately 8.6 miles per year for the next 10 years. The remaining 4 kV bare will take another 10 years.

34.5kV System

BVES will continue on high-risk areas and achieve 30% completion in 2022 towards a program goal of 100% completion by end of calendar year 2026. All bare wire in HFTD Tier 3 to be covered by end of calendar year 2022 provided the USFS approves the permit for this work.

4kV System

BVES will continue on high-risk area and achieve 6% completion in 2022 towards a program goal of 50% completion by end of calendar year 2030. All bare wire in Tier 2 vegetation areas (high risk areas) to be covered by end of calendar year 2030.

BVES contracts out almost all its covered wire work. This is most efficient because the contractor dedicates its crews to the single focus of performing the covered wire replacement activities, while BVES crews cannot. To replace bare wire with covered wire, the crews need to replace the poles in the assigned segment that are designated for replacement due to pole strength analysis. Then the crews need to set up each pole to receive the covered wire. The covered wire is then pulled by the crews and cutover to each pole. Finally, the bare wire is removed. BVES has a small group of linemen that must focus on customer issues and other responsive activities essential to operating the distribution system safely and reliably; therefore, BVES's crews would be constantly interrupted if assigned to conduct covered wire installation. While challenging, BVES has been able to successfully contract sufficient labor resources to meet BVES's covered wire WMP targets to date and does not currently anticipate that situation to degrade in the future.

Long-term Operations and Considerations

As a separate initiative from the installation of covered conductor, BVES will maintain the installed covered conductor in accordance with prescribed maintenance standards and industry best practices. This will include remediation and adjustments to installed covered or insulated conductors. This will reduce the chance of degradation to the covered wire and potential for ignition sources to develop. BVES reported minimal maintenance requirements for the installed covered conductor and spent $29,400 in 2021. BVES will be allocating maintenance resources to properly maintain the covered wire according to standards. BVES will apply any lessons learned throughout the progression of the program.

As part of the Radford Line Replacement Project, BVES will install utility fiber cable and will use this for future system monitoring efforts (cameras, infrared sensors, system diagnostics sensors, etc.) and for fast acting switches on the circuit.

Key Assumptions

BVES assumes that covering conductor is a cost-effective means to significantly reduce the risk of ignition. While not as effective at reducing ignition risk as undergrounding, the installation of covered conductor is known to substantially reduce wildfire risk and is significantly cheaper than undergrounding. The incremental increase in risk reduction achieved by undergrounding when compared to installing covered wire is significantly less than the incremental increase in cost incurred by undergrounding when compared to covered wire. Because the addition of covered conductor often (approximately 50% of the time) requires the replacement of existing wood poles, BVES's system is less likely to have pole failure where it has installed covered conductor thereby increasing the resiliency of the BVES system and reducing the wildfire risk.

Cost Effectiveness Evaluations

BVES spent $6,156,720 (CAPEX) in 2021 covering 12.3 miles of bare wire within Tier 2. Tier 3 is addressed by the Radford Line Replacement Project, which is still in the permitting phase. BVES spent $139,970 on the Radford Line Replacement Project in 2021 in permitting efforts (environmental studies required by the USFS).

BVES compared undergrounding versus covered conductors. Undergrounding is the only other technically acceptable alternative. However, the cost is at least 10 times that of the covered wire replacement project. Additionally, certain areas would be significantly challenging to underground the overhead system and the construction work would be disruptive to the environment. The RSE for the covered wire program is 0.21 whereas the RSE for undergrounding the same circuits is 0.022. Therefore, the covered wire program yields a significantly more attractive RSE.

BVES has budgeted for 12.90 of circuit miles treated each year approximating (CAPEX) $6,570,400 in 2022, $6,836,700 in 2023, and $6,767,600 in 2024.

Other Activities Relevant to Covered Conductor Installation

As discussed above in this section and in **Section 7.3.3.13**, the installation of covered conductor requires pole testing of existing poles and, typically, replacement of approximately 50% of the poles previously supporting the bare wire due to the increased weight and diameter of the covered conductor. The installation of new poles increases the resiliency of the BVES system to high winds.

Data Sources

BVES derived its data from its own experience and that of other utilities. Specifically, BVES participated in the Joint IOU workshops on the effectiveness of covered conduction, as indicated in the workshop report "2022 WMP Update Progress Report." For example, SCE estimated full deployment of covered conductor in high-risk areas to mitigate approximately 60 percent of fires associated with electrical distribution facilities in defined risk tiers.[63] BVES believes SCE's effectiveness results should be considered a relative measure, with underground conversion providing the baseline (100 percent) for purposes of our comparison. This also aligns with the findings of the covered conductor working group, of which BVES is an active participant.

9.4 Undergrounding Implementation Reporting

In Section 7.3.3.16 Undergrounding of electric lines and/or equipment, report on the following key information for undergrounding implementation:

Methodology for installation and implementation

Design and design considerations (such as permitting requirements, additional hardware needed for installation, etc.)

Implementation (including timeframes, prioritization, contractor and labor needs, etc.)

Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.)

Key assumptions

Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)

Any other activities relevant to the undergrounding implementation This information must be derived from utility-specific programs.

BVES is not currently undertaking or planning any significant undergrounding projects as part of its wildfire mitigation program as discussed in **Section 7.3.3.16**.

Methodology for installation and implementation

BVES conducts routine minor undergrounding upgrade projects in residential neighborhoods.

Design and design considerations

This activity addresses the utility actions taken to underground (UG) electrical lines and equipment in accordance with GO 128. Converting circuits from overhead to underground nearly eliminates the risk of ignition and exists minimally surrounding the area where equipment resurfaces. Because much of BVES's service area is mountainous, rural, and rocky terrain, there are significant challenges in undergrounding both from a construction standpoint and environmental concerns; especially, in areas under the jurisdiction of the USFS.

Implementation

BVES conducts small undergrounding projects for new developments and services and minor upgrades to existing facilities. When feasible, BVES works to install UG facilities for new developments and services to reduce the number of overhead facilities and therefore the risk those facilities pose to wildfire.

[63] SCE application for approval of its Grid Safety and Resiliency Program, U 338-E, September 10, 2018

BVES also conducts small upgrades to existing UG facilities so that service is safe, reliable, and of high quality. All of these projects are in the Tier 2 HFTD.

Long-term operations and considerations

BVES has considerable experience in operating and maintaining underground distribution lines in neighborhoods, Big Bear's urban core, and along roadways. BVES works closely with the City of Big Bear Lake and the County of San Bernardino and neither have indicated any future desire for underground districts.

Key assumptions

BVES will continue to install or upgrade underground lines where feasible. BVES does not plan on converting any significant stretches of overhead line to underground.

Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)

The RSE value for this initiative (minor undergrounding projects) is 3.82. BVES spent $508,648.86 (CAPEX) in 2021 on this initiative activity and estimates a budgeted spend of $75,000 in 2022, $312,200 in 2023, and $309,000 in 2024.

It should be noted, and as discussed in the previous **Section 9.3**, BVES compared undergrounding with covered conductors as undergrounding is the only other technically acceptable alternative. However, the cost would be at least 10 times that of the covered wire replacement project. Additionally, certain areas would be significantly challenging to underground the overhead system and the construction work would be disruptive to the environment. The RSE for the covered wire program is 0.21 whereas the RSE for undergrounding the same circuits is 0.022. Therefore, the covered wire program yields a significantly more attractive RSE.

Any other activities relevant to the undergrounding implementation

BVES will continue to evaluate the cost-effectiveness and RSE of undergrounding and will consider as an alternative to overhead projects where feasible.

APPENDIX A. WSD-022 ISSUE RESPONSE

The responses below address the 14 issues identified in OEIS's Final Action Statement on BVES's 2021 WMP.

A.1 BVES-21-01: Inadequate Disaggregation of Expenditure

Table 1 below highlights the following issue requiring a complete remedy in the 2022 WMP Update. BVES presents its progress and movement toward addressing the concern in this Progress Report to the OEIS.

Table 1: BVES-21-01

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-01	Inadequate disaggregation of expenditure	As discussed in Section 1.2 of the 2021 Action Statement, BVES was required to disaggregate its WMP expenditure for its Revision Notice Response. However, Cal Advocates discovered that 17 of BVES's initiatives have the same expense amount in 2020, 11 in 2021, and 13 in 2022. In response to a Cal Advocates' data request, BVES states that it spreads certain expenses equally across multiple initiatives, but BVES offers no quantitative analysis to support such allocation.	For its **2022 WMP Update**, BVES must identify where common costs are allocated across multiple initiatives. In addition, BVES must justify its allocation methodology by describing these common costs in detail, explaining how they relate to each initiative and demonstrating that the allocated values reasonably reflect the initiatives' true costs.

On May 4, 2021, the Wildfire Safety Division's (WSD) issued its Revision Notice to BVES regarding the utility's 2021 WMP Update. The WSD (now the OEIS) advised BVES to address two critical issues, which included the need for disaggregation of expenditures related to the 86 approved initiatives. With respect to deficiency BVES-01, WSD found that BVES failed to use WSD-defined initiatives and labeling in Section 7.3 of its 2021 WMP Update and required BVES to submit a revised Section 7.3 that adheres to the 2021 WMP Guidelines. BVES provided this update in the 2021 WMP Update Revision on June 3, 2021. Within the second Finding BVES-02, the deficiency notice requires that additional description of aggregated spending on certain initiatives be documented with a revised Table 12 from the Quarterly Data Report (QDR). On June 23, 2021, the Public Advocates Office (Cal Advocates) submitted reply comments regarding BVES's revisions to its 2021 WMP Update.

BVES has worked to develop accounting methods to more accurately capture mitigation measures across multiple programs and projects as they correspond with risk reduction efforts of the 88 initiatives. BVES understands that imprecise accounting could yield misappropriated Risk-Spend Efficiency (RSE) scores and thus skew risk methodology outputs. Historically, the utility has measured effectiveness through successful implementation of described initiatives. This process is reflected in the latest quarterly reports in 2021 highlighting a practice to track, record, and project capital and operating expenditures attributed to each of the applicable initiatives. It should be noted that most of the values to which this cost allocation method has been applied are less than $10,000 per year. In preparing its next WMP, BVES will perform sensitivity analysis to determine the extent to which cost estimation may impact certain RSE values.

BVES recently submitted third quarter updates in late 2021 with its applied accounting practice methodology and in its subsequent quarterly reports. This approach is also incorporated in the 2022 WMP Update and the 2022 Annual Report on Compliance.

A.2 BVES- 21-02: Program Targets are Unmeasurable and Difficult to Track

Table 2 below highlights the following issue requiring a complete remedy in the 2022 WMP Update. BVES presents its progress and movement toward addressing the concern in this Progress Report to the OEIS.

Table 2: BVES-21-02

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-02	Program targets are unmeasurable and difficult to track	The 2021 WMP guidelines defines program targets as “quantifiable measurements of activity.” In Table 5.3-1: List and Description of Program Targets, Last 5 Years, BVES lists 86 program targets; 32 of these targets have no numerical target and 42 targets are quantified by the unmeasurable unit “Percent Project Milestones Completed” (or similar).	In its **2022 WMP Update**, BVES must: Only include quantifiable measurements of activity in its list of program targets in Table 5.3-1 (or similar). To the extent possible, modify existing targets to use measurable units. For example, the unit for intrusive pole inspections should be “# of Pole Inspections” rather than “Percent of Scheduled Circuits Completed.” If using milestones as a sign of progress, describe milestones in Section 7.3 under appropriate initiatives.

BVES has been working to translate initiative targets into quantitative assessments and value-based measurements to align with legacy tracking metrics. BVES has utilized progress-based tracking for most measures and, through lessons learned of project execution, is modifying existing metrics to generate values that can be tracked for trends and risk reduction outputs.

To address

Item 1: BVES will, to the extent possible, modify its future 2022 QIU units to represent quantifiable trackable execution targets, in addition to those with a qualitative unit measurement. BVES notes that several trackable measurements will change for the upcoming WMP cycle to properly address this issue. BVES will also look at what other utilities have used to establish quantitative metrics for WMP initiatives and see how BVES can make similar metric work for BVES WMP initiatives.

Item 2: BVES will review current targets and modify those that are qualitative into numerical tracking functions for quantitative targets, to the extent possible. BVES has historically followed its practices through percentages of completion due to the moderate size of its service area and ability to inspect and harden infrastructure reaching 100 percent of assets throughout a program period. This approach will be enhanced starting in 2022 for more precise measurements.

Item 3: For initiatives requiring progress milestones that have descriptive elements for internal key performance metrics, BVES made these goals available in the 2022 WMP.

A.3 BVES-21-03: Vegetation Inspection Roles Lack Minimum Forestry and Arboriculture Qualifications

The following issue has been identified for a progress report update in Table 3.

Table 3: BVES-21-03

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-03	Vegetation inspection roles lack minimum forestry and arboriculture qualifications	As discussed in Section 1.2 of the Action Statement, BVES was required None of the roles described in Supporting Table 5.4.1-1 include minimum qualifications in forestry and arboriculture. In contrast, Liberty and PacifiCorp require their vegetation inspection personnel to either have ISA Arborist Certification, be a Register Professional Forester, or have some arboriculture experience. Energy Safety is concerned that BVES does not hire qualified workers to conduct vegetation inspections.	BVES must: 1. Provide evidence that its vegetation inspection personnel are adequately qualified and trained to perform vegetation inspections. 2. Include forestry and/or arboriculture certifications and/or experience as minimum qualifications for appropriate vegetation inspections roles.

BVES requires its vegetation inspection contractors to maintain adequate evidence of qualified training. Additionally, BVES geographically employs a higher number of arborists per square mile compared to California regulated utilities due to its 32-square mile service territory. Whereas a team of tree crews may have responsibility for a larger service territory region of a neighboring utility, BVES's service area is small enough to be uniquely managed by a mid-size crew, supported by a contracted forester, along with internal field crew and linemen that periodically assist in vegetation clearing activities. BVES is thus able to address a larger swath of its territory year over year in part with detailed inspection cycles. This is similar per circuit mile of managed and operated electrical lines. BVES also contracted with a forester to provide observational support during vegetation management activities, providing additional oversight and work verification during activities performed in the field.

BVES acknowledges that information was not detailed in full; however, BVES provides the following evidence to address Items 1 and 2.

Item 1: BVES submits the following evidence that its contractor personnel are adequately qualified.

Contracted Personnel:

Shane Smith (Davey Resource Group) serves as the primary contractor managing BVES's account and holds more than four years of experience as a Utility Forester with three years attributed to certifications through the International Society of Arboriculture Certified Arborist. Mr. Smith also holds a Tree Risk Assessment Qualification

Additional foreman (Mowbray Tree Service) account for:

29 ISA Certified Arborists
One Registered Professional Forester
Two biologists supporting environmental compliance and commitments

BVES Personnel:

1. Paul Marconi (President)

    a. 37 years of engineering and technical experience with electrical power systems including field inspections of equipment
    b. Managed the vegetation management program for four years and provided oversight of the vegetation management program for an additional three years
    c. Has conducted vegetation management clearance inspections for seven years

2. Jeff Barber (Operations Supervisor)

    a. Spent over 42 years in the utility industry
    b. Journeyman Lineman- Trimmed and maintained proper clearances
    c. Power Troubleman – Emergency trimming and identification for planned vegetation crew trimming
    d. Line Crew Foreman – Direct crews during emergency power restoration on proper vegetation clearing
    e. Operations Manager – Developed and directed the day-to-day vegetation trimming program through operations staff
    f. Assistant General Manager of Operations – Oversee the entire vegetation management program for Pasadena Water and Power Municipal Utility (PWP) – under my program implementation and oversight, for 17 years PWP received the highest award given to a utility vegetation program; the Tree Line Utility USA award given by the National Arbor Day Foundation

3. Jon Pecchia (Utility Manager)

a. BS and PE Chemical Engineer
b. Five months of quality check (QC) tree trims
c. 10 years as environmental consultant conducting site inspections and project management involving a variety of environmental and safety issues
d. 13 years of experience in general management of industrial equipment used in hazardous areas

4. Tom Chou (Utility Engineer and Wildfire Mitigation Supervisor)

    a. 13 years as an Electrical Engineer
    b. Eight Years with BVES as substation designer, transmission/distribution designer and compliance engineer
    c. Five months of conducting QC experience for vegetation management

5. Jared Hennen (Wildfire Mitigation and Reliability Engineer)

    a. 10+ years as a wildland firefighter, three of which were utility firefighter contracted by San Diego Gas & Electric and Pacific Gas & Electric
    b. Almost one year of conducting tree trim QC for BVES
    c. Manages the vegetation management programs at BVES

6. Anthony Rivera (Field Inspector)

    a. 23-year Journeyman lineman
    b. Managed vegetation management program at BVES for almost two years
    c. 15 years contractor and project management

Item 2: A listing of certifications and relevant experience is described below that communicate minimum qualifications for inspection roles.

All Mowbray's tree crews possess the following:

Environment Health and Safety Training
California Occupational Safety and Health Administration Hazards Training
Fire Prevention and Chemical Handling Training
Electrical Hazard Awareness Training
First Aid and cardiopulmonary resuscitation Training
Aerial Rescue Training
All requirements for Line Clearance Compliance

A.4 BVES-21-04: No Climate Driven Risk Mapping

Table 4 below highlights the following issue requiring a complete remedy in the 2022 WMP Update. BVES presents its progress and movement toward addressing the concern in this Progress Report to the OEIS.

Table 4: BVES-21-04

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable

BVES-21-04	No climate driven risk mapping	BVES does not have a program that addresses climate- driven risk mapping.	In its **2022 WMP Update**, BVES shall describe how it applies risk analysis models to consider future climate projections.

In 2021, BVES developed risk-based initiatives and predictive fire behavior models that incorporate climate-driven parameters and conditions. Utilizing REAX Engineering, an experienced firm operating in California and with great reach into the evolution of California's high fire threat district (HFTD) map development, BVES recently showcased initial modeling results at the October 5, 2021, OEIS-led Risk Mapping Working Group.

Weather and climate assumptions are an implicit layer within the risk maps, which includes current climatological conditions with real time mesoscale analysis over an hourly forecast at 2.5-kilometer resolution, with a historical impact probability with fuel thresholds over the last ten years. Additionally, modeling layers include climate adjusted conditions for a mid-century look illustrating potential affects during years 2046-2055.

A full report is currently being developed in contribution to the working group workshops. BVES will provided this complete update in its 2022 WMP update. Below are several image stills resulting from the modeling activities.

Figure 1: Current Conditions Risk of Fire Area

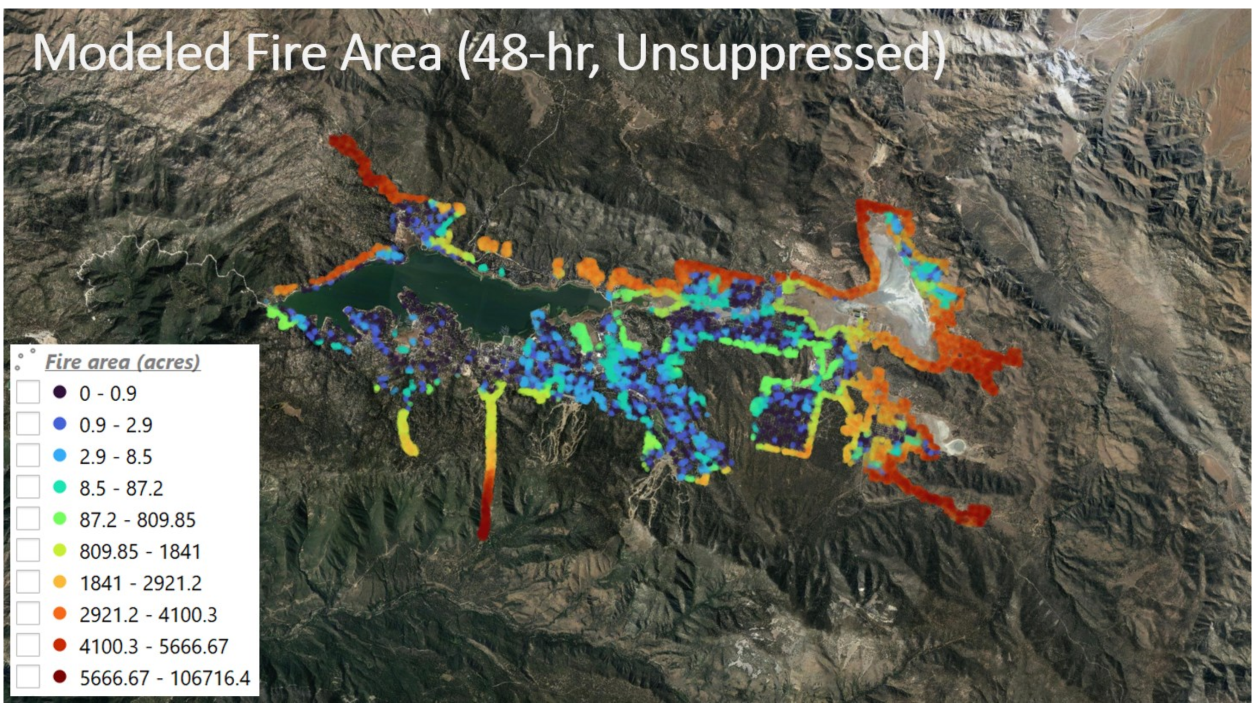
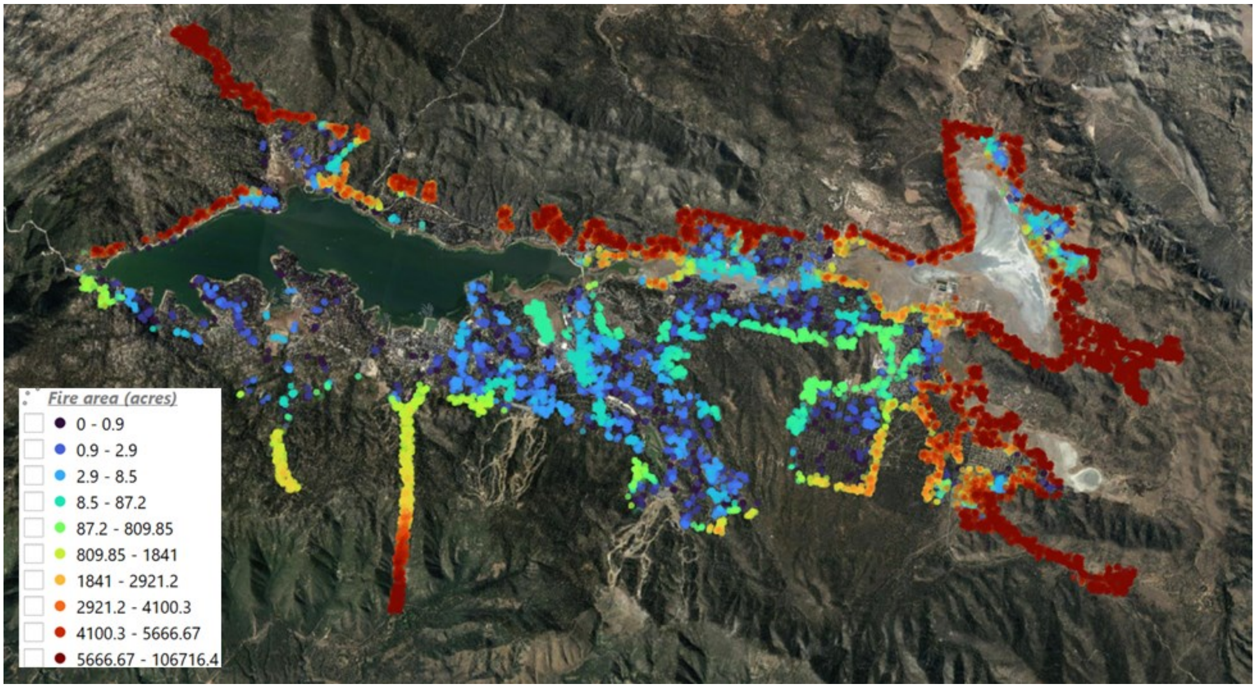


Figure 2 2050 Conditions Risk of Fire Area



A.5 BVES-21-05: Lack of Consistency in Approach to Wildfire Risk Modeling Across Utilities

The following issue has been identified for a progress report update in Table 5.

Table 5: BVES-21-05

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-05	Lack of consistency in approach to wildfire risk modeling across utilities	The utilities do not have a consistent approach to wildfire risk modeling. For example, in their wildfire risk models, utilities use different types of data, use their individual data sets in different ways, and use different third-party vendors. The WSD recognizes that the utilities have differing service territory characteristics, differing data availability, and are at different stages in developing their wildfire risk models. However, the utilities face similar enough circumstances that there should be some level of consistency in their approaches to wildfire risk modeling statewide.	The utilities must collaborate through a working group facilitated by Energy Safety to develop a more consistent statewide approach to wildfire risk modeling. After Energy Safety completes its evaluation of all the utilities' 2021 WMP Updates, it will provide additional detail

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
			on the specifics of this working group. A working group to address wildfire risk modeling will allow for: 1. Collaboration among the utilities; 2. Stakeholder and academic expert input; and 3. Increased transparency.

BVES participates in the OEIS Risk Mapping Working Group, which commenced in early October 2021. Part of the initial conversations centered around understanding each of the IOU methodologies for demonstrating risk assessment approaches, as well as current modeling techniques and data elements embedded within those models. Details on lessons learned, methodologies and modeling approaches, and movement toward a more standardized approach will be better communicated in the 2022 WMP update, following the initial working group meetings to occur in late 2021.

Item 1: Collaboration among the utilities will continue through the established modeling workshop, though, BVES has not yet engaged directly on mapping approaches among SMJUs.

Item 2: BVES contracted with an experienced wildfire risk modeling subject matter expert with broad expertise on aspects of California's high fire threat district zone mapping process. This consultant worked over the second half of 2021 to produce updated risk maps for BVES, recently updated to the OEIS on October 5, 2021.

Item 3: Increased transparency in the processes to arrive at the current risk maps is an important piece of the working group engagements. BVES submitted a detailed description of its risk methodologies to the OEIS on October 13, 2021.

A.6 BVES-21-06: Disparities Between BVES's Situational Awareness and Forecasting Capabilities and Maturity Model Reporting

The following issue has been identified for a progress report update in Table 6.

Table 6: BVES-21-06

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-06	Disparities between BVES's situational awareness, forecasting capabilities, and maturity model reporting	BVES had a significant increase in its maturity assessment ratings for situational awareness and forecasting in its WMP update. The ratings are much higher in comparison to peer utilities and prior reporting in 2020. It remains unclear if the ratings selected are accurate representations of BVES's maturity, as the explanations in the initiatives do not explain these improvements.	BVES must describe: How it intends to collect and measure physical impacts of weather on its grid, such as sway in lines and sway in vegetation. How it plans to include wind estimations at various atmospheric altitudes relevant to ignition risk. What initiative it has or how it is using ignition detection software. How it plans to accurately forecast weather at least three weeks in advance.

In responding to the Maturity Model questions, BVES interpreted the instructions as follows:

"Cycle" is three years.
"Start of cycle" is January 2021.
"By end of year 1 (current)" is December 2021.
"Planned state by end of cycle" December is 2023.

Item 1: Regarding how it intends to collect and measure physical impacts of weather on its grid, such as sway in lines and sway in vegetation (Maturity Model: 6a: What weather data is currently collected?), BVES provided the following responses:

6a: What weather data is currently collected?

BVES Response for "Start of cycle": iii. Range of accurate weather variables (e.g., humidity, precipitation, surface and atmospheric wind conditions) that impact probability of ignition and propagation from utility assets.

BVES Response for "By end of year 1 (current)": iii. Range of accurate weather variables (e.g., humidity, precipitation, surface and atmospheric wind conditions) that impact probability of ignition and propagation from utility assets.

BVES Response for "Planned state by end of cycle": iv. Range of accurate weather variables that impact probability of ignition and propagation from utility assets; additional data to measure physical impact of weather on grid collected (e.g., sway in lines, sway in vegetation).

In responding to this question, BVES considered in its response that it is developing the ability to use its most current LiDAR survey to estimate the extent of sway in vegetation at various wind speeds and identify limiting areas and wind speeds by the end of 2023. BVES does not operate any long spans that make its lines susceptible to sway (e.g., BVES does not operate transmission lines); therefore, line sway will not be pursued at this time.

Item 2: Regarding wind estimations at various atmospheric altitudes relevant to ignition risk (Maturity Model: 7a: How granular is the weather data that is collected?), BVES provided the following responses:

7a: How granular is the weather data that is collected?

- BVES Response for “Start of cycle”: iii. Weather data has sufficient granularity to reliably measure weather conditions in HFTD areas, along the entire grid, and in all areas needed to predict weather on the grid.

- BVES Response for “By end of year 1 (current)”: iii. Weather data has sufficient granularity to reliably measure weather conditions in HFTD areas, along the entire grid, and in all areas needed to predict weather on the grid.

- BVES Response for “Planned state by end of cycle”: iv. Weather data has sufficient granularity to reliably measure weather conditions in HFTD areas, along the entire grid, and in all areas needed to predict weather on the grid. It also includes wind estimations at various atmospheric altitudes relevant to ignition risk.

BVES has installed all 20 planned weather stations throughout its 32-square mile service territory at varying elevations. BVES’s weather consultant has access to BVES owned weather stations, as well as other weather stations on several mountain peaks, in the lower elevations of Big Bear Lake (lake level), and other lower elevations below the BVES service territory. Therefore, BVES is working with its consultant to attempt to include wind estimations (forecasts) at various atmospheric altitudes relevant to ignition risk in forecasts.

Item 3: Regarding ignition detection software (Maturity Model: Item 10d: What role does ignition detection software play in wildfire detection?), BVES provided the following responses:

10d: What role does ignition detection software play in wildfire detection?

BVES Response for “Start of cycle”: i. Ignition detection software not currently deployed.

BVES Response for “By end of year 1 (current)”: i. Ignition detection software not currently deployed.

BVES Response for “Planned state by end of cycle”: iii. Ignition detection software in cameras operates automatically as part of ignition detection procedures.

In responding to this question, BVES was referring to the ALERTWildfire cameras that it installed in partnership with UCSD. These cameras currently do not include ignition detection software. It is BVES’s understanding that ALERTWildfire is developing software to detect ignitions. BVES has re-evaluated the response to “Planned state by end of cycle” to be “ii. Ignition detection software in cameras used to augment ignition detection procedures” and will update its response in the next maturity survey. However, BVES will continue to collaborate with UCSD on this issue.

Item 4: Regarding the ability to forecast weather in advance (Maturity Model: Item 8b: How far in advance can accurate forecasts be prepared?), BVES provided the following responses:

BVES Response for “Start of cycle”: ii. At least two weeks in advance.

BVES Response for “By end of year 1 (current)”: ii. At least two weeks in advance.

BVES Response for “Planned state by end of cycle”: iii. At least three weeks in advance.

BVES is working with its weather consultant to obtain longer range forecasting. This effort includes improving the weather models used in forecasting, if possible. BVES notes that this goal is currently not achievable but may be achievable by the end of 2023.

A.7 BVES-21-07: Lack of Detail on Prioritization of Initiatives Based on Determined Risk

The following issue has been identified for a progress report update in Table 7.

Table 7: BVES-21-07

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-07	Lack of detail on prioritization of initiatives based on determined risk	BVES does not provide any details on the actual prioritization of its grid hardening efforts, despite having determined the highest risk circuits along its system. Instead, BVES relies on the Tier 2 and Tier 3 HFTD designations to justify prioritization. BVES fails to provide the details on how the timing of deployment of its grid hardening efforts mitigate its highest risk areas and fails to provide a plan that demonstrates it is addressing and mitigating its highest risk areas.	BVES must: 1. Explain how the timing of deployment of its grid hardening efforts are based on its risk calculations and prioritize mitigating its highest risk areas; and 2. Provide a plan that demonstrates that BVES is addressing and mitigating its self- identified highest risk areas through system hardening initiatives.

The scale, geographical context, and topography associated with BVES’s 32-square mile service territory which covers rural and mountainous terrain at approximately 7,000 feet within the San Bernardino Mountains is conveyed in BVES’s Risk Register. Vegetation conditions include a heavily forested environment with mostly dry climatological conditions spanning 80.5 percent of the service area. Fuel conditions include conifers such as ponderosa, Jeffrey, sugar, coulter, and lodgepole pines with minimal cheatgrass and shrubs. BVES’s territory is entirely within the HFTD with mostly Tier 2 and a small percentage in Tier 3 and is located within the Heavy Loading District (greater than 3,000 feet).

The Risk Register identifies the top asset-related risks to the service territory and electrical infrastructure and guides incremental mitigation strategies beyond those already in place. The 7x7 Logarithmic Risk Matrix identifies the frequency of hazardous events and the possible consequences and impacts such as those associated with reliability, compliance, quality of service, safety, and environmental damage. BVES equipment and operations have not ignited any fires in recent years, though, the potential for such ignitions and their consequences are considered in the data. Additionally, BVES has not initiated a Public Safety Power Shutoff (PSPS) event, but the model considers the consequential outcomes of such actions. BVES performs quality checks for data inputs semi-annually and performs an annual calibration event.

Item 1: The Risk Register and risk-based decision-making methodology includes weighted score indices to calibrate frequency and impact. Frequency is defined as “number of events per unit of time.” It is a measure of how often a risk event has occurred or is likely to occur. The impact measure is the approximate worst reasonable case of a specific risk event. These results influence the risk score rating of the Fire Safety Circuit Matrix, the principal planning guide utilized by BVES staff in scheduling grid hardening activities across all evaluated circuits.

The timing and deployment of grid hardening efforts are currently linked to the scoring resulting from BVES’s Fire Safety Circuit Matrix, which is derived from the Risk Register determination of risk drivers and probabilistic consequences. The Fire Safety Circuit Matrix exists to quantify the unique assets, inspection conditions, and available risk drivers per circuit managed by BVES. BVES understands that segmentation of the circuits to determine granularity of risk by span has not yet been integrated into the methodology. BVES notes that each circuit is inherently smaller than one segment of a comparable IOU due to the nature of the service area size. In the future, BVES will use the risk maps and models generated in the second half of 2021 in the design, prioritization, and planning of its mitigation activities to address segments of line more prone to ignition risk.

Timing and deployment of activities are also characterized through the CPUC’s HFTD Tier 3 and Tier 2 determinations, followed with risk driver and consequence assessments attributed to each of the circuits. This includes circuits with legacy devices prone to sparking or arcing, incidents found through inspection cycles, pole loading and replacement determinations, outage history, and other at-risk details resulting in a weighted rating of “high,” “medium,” and “low” risk. Scheduling and execution may also be challenged by seasonal restrictions, permitting timelines, access to materials and resources, and contractor availability. These unknown externalities are not mapping within the Fire Safety Circuit Matrix but are discussed in planned implementation of the WMPs.

Item 2: BVES currently utilizes its engineering department resources to determine which lines to work on based on the results of the risk methodology framework and Fire Safety Circuit Matrix. RSE values are determined through the Risk Register, accounting for cost-beneficial hardening strategies in conjunction with enhanced routine vegetation management and inspection practices. The potential impacts of the worst reasonable scenario across six identified impact categories are rated between one and seven, with seven as the greatest severity.

Once the impact is articulated, frequency of consequence is established, based on data, and a subject matter expert is assigned to each scenario. The Risk Register then applies a formula to create a score between zero and 1,000,000,000. Direct impacts of climate change are considered, as well as invasive species and other impacts, such as the recent bark beetle infestation. The Risk Register calculates a total risk score from the data collected in risk analysis.

BVES plans to address each of the utility’s circuits over ten years with remedies applied to each prioritized as “highest risk” based on the weighted formula score. Results can be assessed by way of number of circuit miles hardened, bringing the risk impact down by a percentage or numerical value. Due to the nature of the HFTD and BVES’s entire service area making up mostly Tier 2 and a few miles of the Radford Line in Tier 3, the utility plans to address all circuits within priority areas determined through the process described above.

Future updates will include the risk mapping models generated in mid-2021. These maps (illustrated in Figure 1 and 2) will allow BVES to identify circuit segments with the greatest ignition and consequence potential in conjunction with the risk methodologies discussed above. These resources will allow BVES to plan its mitigation initiatives to maximize effectiveness of its efforts.

A.8 BVES-21-08: Limited Evidence to Support the Effectiveness of Covered Conductor

The following issue has been identified for a progress report update in Table 8.

Table 8: BVES-21-08

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-08	Limited evidence to support the effectiveness of covered conductor	The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full understanding of its long-term risk reduction and cost-effectiveness. The utilities' current covered conductor pilot efforts are limited in scope and therefore fail to provide a full basis for understanding how covered conductor will perform in the field. Additionally, utilities justify covered conductor installation by alluding to reduced PSPS risk but fail to provide adequate comparison to other initiatives' ability to reduce PSPS risk.	The utilities must coordinate to develop a consistent approach to evaluating the long- term risk reduction and cost-effectiveness of covered conductor deployment, including: 1. The effectiveness of covered conductor in the field in comparison to alternative initiatives. 2. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.

BVES investigated methods to capture the risk reduction and cost-effectiveness of covered conductors across California and North America through internal engineering reviews, external consultant support, and discussions with the IOUs. To date, a formalized approach arriving at a consistent methodology among utilities has not been established, though BVES acknowledges several IOUs have communicated lessons learned and execution successes and challenges related to deploying covered conductor types.

BVES is amenable to working with similar utilities to develop a cohesive stance on insulated wire best practices, though, it understands that this process is continuing to evolve across the greater west as utilities opt to harden systems with greatest risk reduction, in cost-effective manners. Coordination begun informally in the fall of 2021 during lessons learned discussions with affected utilities of wildfire ignitions and a newly established technical working group addressing covered conductor approaches, successes, and challenges. BVES plans to draw from these discussions with other California regulated utilities.

Item 1: BVES evaluated several approaches for replacing bare wire with hardened materials. BVES closely followed the common deployment approaches of California utilities such as pilots led by Southern California Edison (SCE) and PG&E as well as insight gained from the technical workshops held at the

CPUC in 2019 and 2020. Technical specifications, manufacturer saturation, and deployment varieties of covered conductor within the industry across areas of the northeast and Canada were also reviewed.

BVES determined primary tree wire conductor cables to be most effective based upon engineering, financial viability, and risk reduction needs of BVES OH assets. This is primarily due to the fire-retardant insulation design within the shield layers and open-air design of the shielded cables. These devices allow for an open wire configuration on cross-arms (or armless brackets depending on the line design) with polyethylene insulation versus spacer cables that are configured with a multi-messenger, heavily insulated conductor construct. The functionality of either sheath coverings or bare wire intrinsically provide similar risk reduction benefits in insulating electrical wire and mitigating sparks and faults from outside contact on the line between the two designs. However, BVES generally found primary tree wire to be more responsive in fault reduction through field analysis as it prevents transference of fire or ignition and localizes the threat in a confined area. Additionally, this design was found to be more economical, allows BVES to readily stock materials, and passed loading tests based on BVES's conductor span lengths and voltage classes. BVES continues to evaluate new and evolving products in this space in due diligence activities of mitigation initiative selection processes.

Aerial spacer cables and undergrounding lines were considered as alternative constructs. Insulation materials were also vetted. BVES opted not to utilize aerial spacer cables due to unfit design needs for its voltage classes, availability of materials, high cost, and the strength being concentrated within the engineering construct of the messenger infrastructure, which may result in greater maintenance response, and other factors.

BVES's position as a result of fire damage to lines is to replace bare conductors with stockpiled materials of primary tree wire cables and remediate or replace new poles with fire-resistant materials during recovery activities. While BVES has not experienced catastrophic loss due to wildfires, the utility can more quickly rebuild a line with hardened conductors as opposed to the time delay that may be found with alternative constructs such as spacer cables or undergrounding lines immediately following the ignition event.

Undergrounding has occurred in BVES's territory in high concentrated residential areas and has been considered and evaluated for the Ute line in 2019 (however, was later abandoned due to alternatives). BVES continues to evaluate potential undergrounding alternatives, though, finds the schedule timeline, permitting requirements, and costs to be prohibitive.

Item 2: In relationships to reduction of PSPS risk, BVES gained insight based on its engineering reviews and demonstrations from other utilities. This is because BVES has not had to activate a PSPS event. BVES remains, however, prepared with plans, procedures, and switching mechanisms if a PSPS is needed. BVES finds that covered conductor usage is most effective in reducing PSPS risk with consideration of cost-effective approaches. While undergrounding circuits may nearly entirely reduce ignition risk or the need to proactively de-energize, the useful case is not appropriate for BVES due to several factors such as high-cost projections, environmental concerns, potential permitting delays, and a longer lead time for deployment.

Once the utility implements covered wire on a circuit or segment, nearby and adjacent facilities and structures are assessed for high wind impacts. This leads to the understanding that structural failure is greatly reduced due to hardening circuits through covered conductor approaches. BVES acknowledges that blow-ins from vegetation, felled trees, or large branches can still occur during high wind events, though this risk is managed through enhanced right-of-way clearances, increased cycle inspections, and the intrinsic design of the shield covering reducing electrical sparks. BVES also evaluated the success rate of hardened poles with composite, steel, and fire retardant applied through three-dimensional assessment models. These modifications in conjunction with covered wire furthered ignition and fault risk reduction. Connector failures are also greatly reduced during downed wire events as the covered conductor can smolder for minutes without igniting fuels on the ground. Fault detection technologies can also reduce risk by isolating faults and identifying when a wire falls due to structural failures, blow-ins, or strong winds.

BVES plans to continue gaining insight from utilities and lessons learned communicated within future technical workshops and report any modifications to business plan developments in a future WMP update.

A.9 BVES-21-09: Lack of Asset Inspection Quality Assurance and Quality Control (QA/QC) Program

The following issue has been identified for a progress report update in Table 9.

Table 9: BVES-21-09

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-09	Lack of asset inspection quality assurance and quality control (QA/QC) program.	BVES is in the process of adopting a formal QA/QC program in 2021 but did not provide dates on when it intends to implement such, did not provide details on its current informal QA/QC process, nor provide details on the scope of the QA/QC program currently in development.	BVES must: 1. Provide a timeline for its implementation of a formal QA/QC process. 2. Explain how it conducts quality checks of its asset inspections prior to the adoption of the formal program. 3. Develop an interim QA/QC procedure for asset inspections between now and the establishment of its new QA/QC program, if such has yet to be adopted, in order to ensure that work is being completed accurately and effectively. 4. Provide updates on the development of its QA/QC program in its Progress Report, including: (i) the scope of the QA/QC program, (ii) procedures of the QA/QC program that BVES has developed, and (iii) the status of the QA/QC program implementation.

BVES monitors all aspects of inspection execution including work verification performed through third-party contractors on an annual basis.

Item 1: A formalized QA/QC instruction was issued at the end of 2021. This is included as Appendix F "BVES Asset & Inspection Quality Management Plan."

Item 2: Currently, equipment inspections are primarily conducted by internal BVES staff as described in the 2021 WMP. Additional detailed inspections are conducted by contract inspectors. The internal inspectors utilize informal procedures and team communication to govern and control most inspection activities, resulting in quick responses and correction activities. This has been a relatively effective process. Being a smaller utility, BVES is uniquely positioned to work directly with field crew and contractors with ability to contact/reach field operators within hours of initial notice.

Additional inspections are performed using a truck-mounted LiDAR inspection performed by a third-party contractor. All inspection records are reviewed by the inspection manager and a summary of findings and issues is issued to the Utility Manager for review.

Item 3: BVES's basic QA/QC process is described below:

Contractor's design/planning group develops work package (instructions, drawings, materials, etc.).
QA/QC: All design/planning work is reviewed by the BVES Field Inspector and/or the Engineering & Planning Department prior to construction to ensure the accuracy of the inspection.
Upon approval from BVES, contractor performs work.
QA/QC: BVES Field Inspector performs in-process QC checks. Discrepancies are resolved by the contractor with BVES oversight.
QA/QC: Upon work completion, BVES Field Inspector performs final inspection of the work in the field and performs the initial work package audit. Upon approval of fieldwork and final work package (as built), an initial billing review is performed and approval for invoicing is given.
QA/QC: Prior to authorizing an invoice for the work, the Project Coordinator performs a work package audit and validates the materials and work performed. Project Coordinator also performs a validation of billing units and ensures the Field Inspector's verification of work completion and approval for billing.

Item 4: In additional to the formal QA/QC program for assets, BVES added a QA component to its VM QC procedural document in Q4 2021, also included as an appendix in the 2022 WMP Update. Activities to develop a framework and approach were initiated with internal discussions among contracted third-party resources, internal staff, and BVES's wildfire mitigation program consultants.

The scope of the QA/QC program expands upon the design and governance structure communicated in the **Item 3** response.
The procedures developed to date have been referenced in response to **Item 3** above.
The status of the QA/QC implementation is on target to be fully implemented in 2022.

A.10 BVES-21-10: Limited Discussion of Community Outreach

The following issue has been identified for a progress report update in Table 10.

Table 10: BVES-21-10

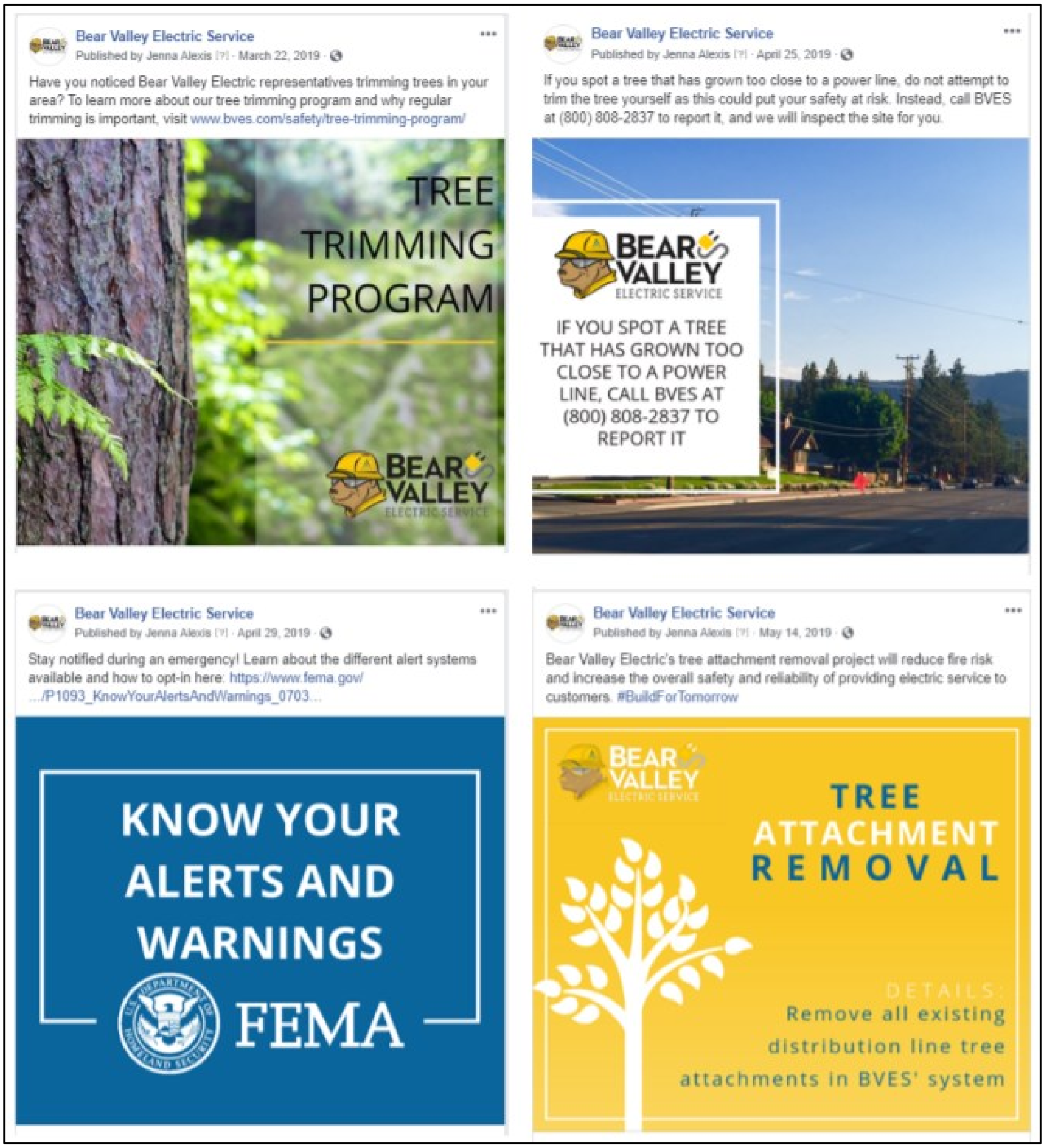
Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-10	Limited discussion of community outreach	BVES-R7 requires BVES to discuss its community engagement and outreach as it relates to VM in Section 7.3.5.1. BVES instead discusses fuels management activities performed by other entities including Big Bear Fire Department and Bear Valley	BVES must: Provide descriptions of notification and communication methods for customers and partner agencies regarding VM activities including, but not limited

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
		Community Service District. BVES mentions outreach efforts to "USFS, CAL FIRE and Big Bear Fire Department in an effort to develop collaborative measures in the area of fuels management," but fails to discuss how it mitigates the community impacts of major VM activities including tree-trimming and tree removal.	to, tree- trimming and tree removal. Detail any efforts in community outreach and public education related to vegetation management.

In addition to the description in **Section 7.3.5.1**, BVES communicates to its customers through a variety of methods regarding vegetation management activities.

Item 1: BVES posted a concise training video on its website to demonstrate the utility's vegetation management program activities. BVES uses social media, bill inserts, communication emails, community workshop discussions, and radio advertisements to alert customers of vegetation management activities, WMP initiatives, and possible PSPS risk during fire season. An example of social media outreach activities is illustrated below.

Figure 3: Social Media Vegetation Management Notices



Item 2: Weekly updates on tree trimming crew locations are provided on BVES's public website. BVES also lists a direct phone line for customers and residents to call with any questions on activities, encroachments on private residences, and to notify the utility if a hazardous vegetation situation or contact is identified. On its website, BVES educates its viewers on appropriate tree planting practices that reduce powerline contacts and differences in tree heights, vegetation density and fuel availability, and locations to plant trees on residential property. Example tips and outage prevention strategies are outlined below:

Call BVES for a free inspection if you suspect a branch is too close to a power line.
Call BVES to disconnect power lines before you remove a tree that may contact a line. We will reconnect once the work is complete.

Never trim or prune a tree within 12-15 feet of a power line. Call BVES first to inspect the tree. In many instances, we'll do the tree work at no cost.
Be aware of the hazards posed by vegetation near power lines. Branches that break and trees that blow over during a storm can cause short circuits, outages, fire, and electrocution.
Clear all flammable vegetation within 30 feet of your home and other structures.
Plant the right tree in the right place. If you must plant near power lines, make sure the maximum mature tree height is 12-15 feet from the closest line.
Never let children climb trees near power lines.
Inspect your trees annually for hazards. For advice, consult a certified arborist.

Additionally, BVES provides a list of frequently asked questions to raise awareness of the types of tree species appropriate for the area with lower contact risk of electrical lines, information regarding the entities performing the tree-trimming activities, how BVES implements recovery support in clearing fallen debris due to winter storms, among other common concerns.

A.11 BVES-21-11: Inadequate Discussion of QA/QC of VM Inspections

The following issue has been identified for a progress report update in Table 11.

Table 11: BVES-21-11

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-11	Inadequate discussion of QA/QC of VM inspections	From the discussion in Section 7.3.5.13, it is difficult to know whether BVES has a QA/QC program for VM. A brief mention of third- party evaluations is the only unequivocal detail. It is unclear whom at BVES performs QA/QC, how often QA/QC is performed, and what goals and targets exist for QA/QC.	BVES must: Describe the "lessons learned from third-party evaluations and inspections." Provide the number of QA/QC evaluation and inspections completed each year. Provide a QA/QC audit target as a percentage of total VM inspections per year. Detail BVES's differentiation between its quality assurance program and quality control program. Report on BVES's plan to add a QA program to the current QC program.

Item 1: BVES tracks lessons learned from vegetation management (VM) QA/QC activities through post-work execution meetings with its contractor service and field personnel also clearing vegetation as part of parallel operations. Following the recent hiring of a qualified forester, BVES is drafting internal review procedures for detailed work verification. The forester started with BVES in Q2 2021 and will be fully utilized by 2022 in day-to-day activities. BVES recently generated a training manual to better position its resources to perform QA/QC activities. BVES also provided decision-tree manuals for clearance standards, which generates a checklist for crew to maintain during day-to-day operations.

Findings from third-party evaluations of vegetation management inspection practices reveal a reduction of vegetation contacts due to programmatic improvements with enhanced vegetation management practices. In 2016, BVES recorded 47 vegetation contacts, 16 in 2017, nine events in 2019, and five in both 2019 and 2020. This data indicates enhanced specifications are having a meaningful impact on reducing bare wire contact events. BVES will gather additional lessons learned as they are recorded and tracked for the 2022 WMP update.

Item 2: As submitted in BVES's Q4 2021 QDR, the figure below presents the inspection clearance findings totals, which also account for QA/QC activities performed over the service area. BVES performs a service area wide inspection practice, with additional activities performed to date as a result of Q4 2021.

Figure 4: Vegetation Inspection Findings YOY

Table 1: Recent performance on progress metrics

Metric type	#	Progress metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021
2. Vegetation clearance findings from inspection - total	2.a.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition - total	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41
	2.a.ii	Number of spans insepcted for vegetation compliance - total	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029
2. Vegetation clearance findings from inspection - in HFTD	2.b.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition in HFTD	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41
	2.b.ii	Number of spans insepcted for vegetation compliance in HFTD	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029

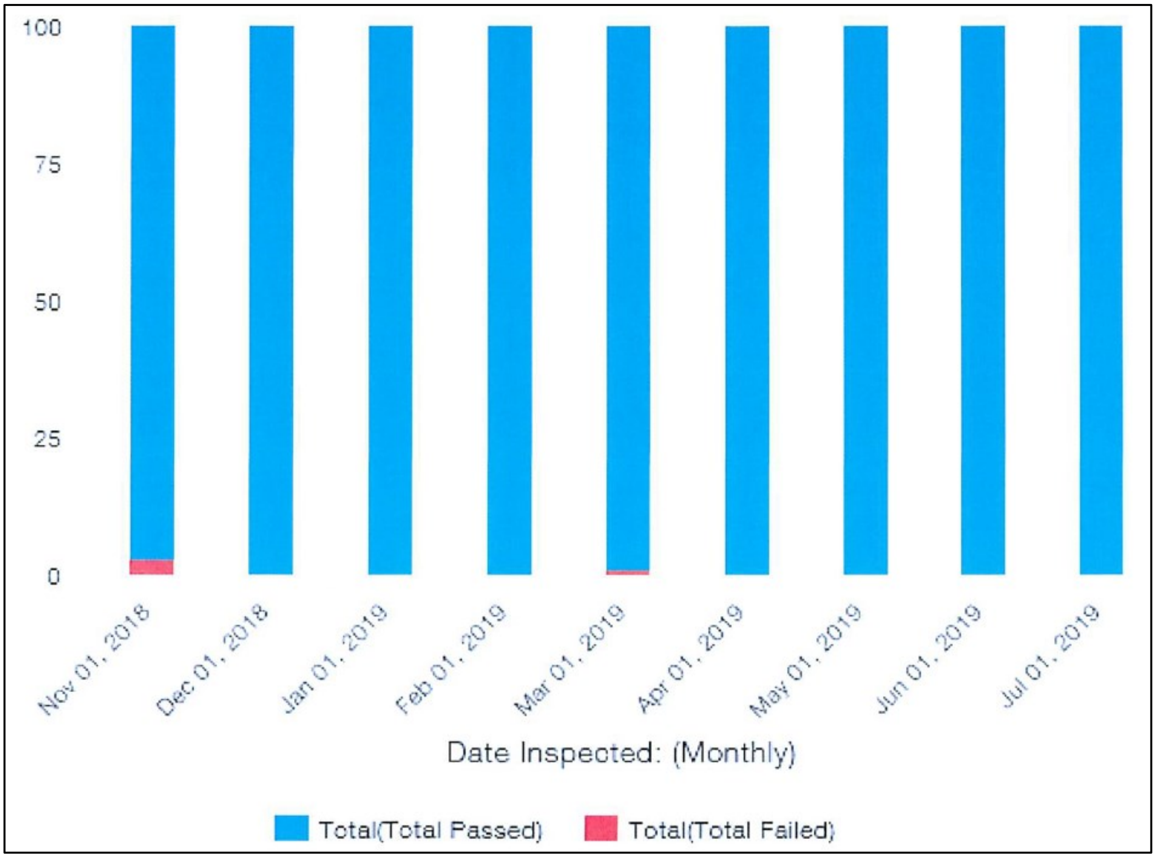
Item 3: BVES VM QC target is 72 VM QC checks of VM clearance work per year. This equates to about 15 percent of the service area. BVES's VM contractor utilizes a three-year plan and clears about 33 percent of the service area per year. Therefore, BVES inspects through VM QC at least 50 percent of the VM contractor's work.

Item 4: BVES conducts frequent QC checks of its vegetation contractor's work execution. Discrepancies noted during QC checks, detailed inspections or patrols of overhead circuits or other means, are generally forwarded to contracted resource via the Kintone Tree Trimming QC application provided by BVES. The contractor responds by marking whether completion of corrective actions is achieved through the software database. Additionally, the contractor documents the vegetation trimming activities performed in the utility right-of-way application to BVES' Partner Software (part of BVES' GIS suite). Discrepancies are designated and corrected as follows:

Emergency (Priority 1) vegetation orders will be corrected immediately (or mitigated to reduce the priority level to at least Priority 2).
Urgent (Priority 2) vegetation orders will be corrected within 30 days.
Routine (Priority 3) vegetation orders will document non urgent items that will be addressed during the regular tree trimming cycle.

BVES utilizes a tree trimming QC program, Kintone Tree Trimming, as part of its internal quality control for vegetation management activities. This database provides several fuel characteristics that are tracked for recordkeeping and presents the number of trees targeted for remediation with those that have passed a QC review and those that have failed. This results in an efficiency rating based on parameters that align with General Order 95 Rule 35 and BVES's enhanced vegetation management practices. An example report product of tracked activities can be found in the figure below.

Figure 5: Kintone Tree Trimming QC Monthly Inspection Summary Example



The log accounts for the number of successful trimming services and inspections performed for at-risk species, which are reported by field crews and digitized into the software with vegetation specifications, photos, and timelines for cycled growth.

Detailed parameters of tracked data elements are collated in the table below.

Table 12: Vegetation Management Verification Functions

Vegetation Management QC Resource	Feld ID/ Metadata	Data Element Description
Kintone Tree Trimming QC Module	Record Number	ID of the Tree Trimming request
	Address	Location of the tree to be trimmed. Usually includes the pole number nearest to the tree
	Infract or Type	The type of job to be performed, depends on the type of tree and the rating of the conductors
	Complete	Flag to identify if the job was completed.
	Comments	Additional comments regarding the job
	Time Frame	General time frame by when the job should be done
	Date Complete	Date When the job was complete
	Due Date (If urgent)	Date by which the job needs to be completed. Only provided if the job is urgent.
	Completed by	Name of the person who did the job
	Reason	Description of the job that was completed
Vegetation Management Report	Corrective / Preventative	Each form must indicate whether the vegetation management work was corrective or preventative
	Due At:	Data by which the vegetation management work is to be performed
	Crew Size:	Number of personnel to engage in the work
	Scheduled Work:	Date and time of the scheduled work
	Pole Number:	Location marker by the adjacent pole number
	Line Number:	The associated line nearby the work performed
	Underground Device #:	If applicable, the underground device related to the vegetation management activity
	Photo Before:	Illustration of the vegetation prior to corrective/preventative action
	Photo After:	Illustration of the vegetation after the corrective/preventative action
	Comments:	Additional comments related to the scope of work
Vegetation Inspection Report	Tree Species:	Toggle options that list the classification of tree based upon the service territory ecology
	Density of Vegetation:	The level of vegetation density determined from the inspection
	Height of Vegetation:	Measurement of the identified vegetation species
	Type of Permission:	Determination of permission of utility to remedy vegetation concerns
	Proof of Permission:	Supporting documents demonstrating permissions
	Trim Info	Check boxes for information related to the status of the tree and nearby lines
	Amount Trimmed (FTS):	The reported amount of vegetation trimmed
	Width:	Width of vegetation
	Work Info:	Check boxes for work completion items
	Date of Visit	Recorded time and date of inspection
	Priority:	Determination of the rank of priority

Vegetation Management QC Resource	Feld ID/ Metadata	Data Element Description
	Suggested Return Date:	Date determined for return routine inspection or as part of a corrective action, depending on the priority level
	Permits	Check boxes for permits in hand related to selected agencies and jurisdictions
	Inaccessible / Special Equipment Needed	Yes / No with additional comments
	Comments:	Additional comments on the scope of work

The VM QA program is part of the quality management program for vegetation inspections and clearing activities that provides confidence VM work meets expectations and requirements are fulfilled. The QA program delivers both:

Internal reports and updates to management, and
External updates to customers, government agencies, regulators, certifiers, and other vested stakeholders.

The VM QA program consists of the following elements:

- Annual VM Program Audit conducted by the Forester, if assigned (if not assigned, the Regulatory Compliance Project Engineer will perform the audit).
  - This activity is conducted at the beginning of each year with an annual lookback at executed work and is intended to be a comprehensive review of the entire VM Program.
  - The Wildfire Mitigation & Reliability Engineer will issue a report of any necessary corrective actions on identified issues in the annual audit by May 1st of each year.
- Quarterly VM Program Assessment conducted by the Wildfire Mitigation & Reliability Engineer
  - The Wildfire Mitigation & Reliability Engineer conducts quarterly assessments in preparation of a quarterly report to senior advisors within BVES. The report includes, among other items, a brief narrative on the status of the VM Program, VM QC checks performed, analysis or commentary on metrics and findings, and any corrective actions taken.
- Periodic VM QC checks are conducted by staff per
  - Evaluators assigned to perform QC checks are provided a map of the assigned circuit areas and a maintained requirements checklist.
  - The Wildfire Mitigation & Reliability Engineer analyzes results of the VM QC checks for trends and recommends a corrective action plan, as necessary
  - The VM QC electronic tracking application, details records of performed activities.

Item 5: BVES recently updated its VM QC Program in early October 2021. With the recent inclusion of a certified contracted forester, BVES is in the process of training and defining an appropriate process. BVES aims to achieve reasonable assurance of executed vegetation management activities performed throughout the year by BVES. BVES is also including a description outlining the QA verification and quarterly/annual audits in **Section 7.3.5.13**.

A.12 BVES-21-12: Spatial Data Issues

The following issue has been identified for a progress report update in Table 13.

Table 13: BVES-21-12

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-12	Spatial data issues	Energy Safety has identified numerous areas for improvement for BVES's Quarterly Data Reports. These issues negatively affect the usability of the data and do not meet Energy Safety GIS Standard. Energy Safety has specified these issues in Table 3 of the Action Statement.	See Table 3[1] for specific remedies related to each data issue. In the November 1, 2021 report, BVES must report on its progress in advancing its GIS capabilities.

[1]Table 3 is labeled as such and directed from WSD-022 Action Statement on BVES’s 2021 WMP.

BVES has continued to enhance its GIS capabilities over 2021 and digitize prior work and inspection implementation and results. In the last year, BVES has executed changes respective to its Gap Analysis for GIS results, identified in November 2020. Since then, BVES has worked with external consultants to carry over training and future mapping needs to acquire in-house staff to ensure data issues are moving toward remediation. BVES has made progress to address the issues discussed in the table below.

Table 14: Spatial Data Issues Remedy Timeline

Data Issue Title	Data Issue Description	Data Remedies Required	Progress to Remedy Issue & Timeline
Empty/null geometry	Of 37 records submitted in the “Red Flag Warning Day” feature, 36 have no geometry. The single record with a polygon associated with it has no attributes.	BVES must follow Energy Safety GIS Data Reporting Standard, including items that require a geometry.	This has been addressed in Q4 2021 before the 2022 WMP Update.
OH and UG conductors separated	Overhead and underground asset line (conductor) data were reported separately, which is not necessary and does not meet the data standard.	Underground and overhead assets comprising the same portion of a utility’s infrastructure (transmission / primary distribution / secondary distribution) are to be submitted in a single feature class, and the field “Asset OH or UG” used to describe the location of each asset.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.

Data Issue Title	Data Issue Description	Data Remedies Required	Progress to Remedy Issue & Timeline
Non-unique primary keys	Primary keys were not unique. Primary key / unique ID fields are fundamental, and data submitted without a unique primary key is not usable.	Each record submitted must have a primary key; each primary key must be unique.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.
Missing foreign keys	The records in the "VM Outages" feature class submitted did not have any values in the "outageID" field, which is the foreign key to the Distribution Outage feature.	Foreign keys must be submitted where specified in the data standard.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.
Domain values not used	In several cases, BVES submitted data which did not conform to the domains specified. One example of this is the "Asset OH or UG" field in the Transformer feature class.	BVES must use coded-value domains where specified in the data standard.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.
Changed field names	BVES submitted data which did not conform to the specifications in many cases. Fields/feature classes listed below do not match the specified names: "Substation" in Primary Distribution Line "DvmOutageI", "Inspection", "Assoc", "Assoc1", "TreeSpecie", "TreeD", "VmOutgDe", "Location", "Y_Coord", and "X_Coord" in VM Outages "Y2_COORD" and "X2_COORD" in Critical Facility	BVES must use feature class and field names specified in the data standard.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.
Removed fields	The data BVES submitted is missing the following fields specified in the data standard: "CircuitName", "SubstationID", and "Conductor Type" in Primary Distribution Line (OH) "CircuitName" and "SubstationName" in Primary Distribution Line (UG) "Basic Object Cause Comment" in Distribution Outage	BVES must not remove fields from the geodatabase template.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.

Data Issue Title	Data Issue Description	Data Remedies Required	Progress to Remedy Issue & Timeline
Changed field type or length	BVES submitted data which did not conform to the specifications in many cases. Fields/feature classes listed below were not of the correct type, or were longer than specified: “Outage Description”, Damaged Device Comment”, “MED”, and “Expulsion Fuse Operation” in Distribution Outage Every string type field in VM Outage feature (11 fields) “Red flag warning issue date” and “Fire Weather ZoneName” in Red Flag Warning Day	BVES must not modify the length or data type of fields.	BVES has updated its GIS package to account for this data issue in the Q3 2021 spatial data QDR submission.

A.13 BVES-21-13: Unexplained changes to risk spend efficiency (RSE) estimates for wildfire and PSPS Mitigation Initiatives

The following issue has been identified for a progress report update in Table 15.

Table 15: BVES-21-13

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-13	Unexplained changes to risk spend efficiency (RSE) estimates for wildfire and PSPS mitigation initiatives	In its 2021 Revised WMP Update, BVES reported six different RSE estimates for wildfire mitigation initiatives and four different RSE estimates for PSPS mitigation initiatives compared to its 2020 WMP without explanation. Refer to Table 4 and Table 5 for specific initiatives and RSE estimates.	BVES must provide all supporting documents and workpapers to justify the changes in RSE estimates outlined in Table 4 and Table 5 of the Action Statement.

There are two components to RSE estimates: (1) risk reduction estimate and (2) annualized cost estimate. The changes in RSE values are almost exclusively due to updating the annualized cost data for each initiative. Each year, BVES reviews and updates cost estimates for WMP initiative to ensure it is reflective of the market (including adjustments for inflation) and any changes to the details of the project scope.

BVES also re-evaluates the risk benefit as well each year. In Table 5 (found as Table 17 of this progress report), the “Install Grid Automation” initiative also had a reduction in “Risk Reduction”. This risk benefit was re-evaluated in preparing the 2021 WMP and it was determined that it was too high.

Table 16: Table 4 Wildfire Mitigation Initiatives RSE Changes

Table 4	2021			2020			Reason for Change in RSE
Wildfire Mitigation Initiatives	Risk Reduction	Cost	RSE	Risk Reduction	Cost	RSE	
Increased Vegetation Management	872292	$2,504,401	0.35	872292	$3,265,11	0.27	Change in annualized cost
Covered Wire Installation Program (34.5 kV)	872292	$2,200,800	0.40	872292	$1,821,994	0.48	Change in annualized cost
Evacuation Route Hardening	1022629	$380,000	2.69	1022629	$1,710,000	0.6	Change in annualized cost
Automatic Recloser Upgrades	1115047	$290,459	3.84	1115047	$300,000	3.72	Change in annualized cost
Install Grid Automation	1148136	$970,422	1.18	1148136	$1,940,845	0.59	Change in annualized cost
Situational Awareness Enhancement Project	1143069	$456,000	2.51	1143069	$342,000	3.34	Change in annualized cost

Table 17: Table 5 PSPS Mitigation Initiatives RSE Changes

Table 5	2021			2020			Reason for Change in RSE
PSPS Mitigation Initiatives	Risk Reduction	Cost	RSE	Risk Reduction	Cost	RSE	
Rebuild Radford Line	2601813	$5,600,000	0.46	2601813	$5,250,000	0.5	Change in annualized cost
Install Grid Automation	1691178	$970,422	2.68	2601813	$1,940,845	1.34	Change in annualized cost & risk reduction benefit
Situational Awareness Enhancement Project	2397142	$456,000	5.26	2397142	$342,000	7.01	Change in annualized cost
Construct Energy Storage Facility	2638046	$13,110,000	0.2	2638046	$9,151,350	0.29	Change in annualized cost

A.14 BVES-21-14: Limited discussion on reduction of scale, scope, and frequency of PSPS

The following issue has been identified for a progress report update in Table 18.

Table 18: BVES-21-14

Utility-#	Issue Title	Issue Description	Remedies Required and Alternative Timeline, If Applicable
BVES-21-14	Limited discussion on reduction of scale, scope, and frequency of PSPS	BVES has limited discussion on its near-term progress for reduction in scale, scope, and frequency of PSPS. BVES stated that due to its minimal use of PSPS in the past, it is unable to further reduce PSPS. Nevertheless, BVES must still report its plans to minimize PSPS scale, scope, and frequency, normalized for weather events and climatic conditions.	BVES must report on its plan to minimize the scale, scope, and frequency of PSPS events normalized for weather events and climatic conditions, and fully describe how its planned mitigation initiatives minimize PSPS impact.

The appearance of limited discussion on BVES's near-term progress for reduction of scale, scope, and frequency of PSPS has been inherently tied to lack of any activation of PSPS events since the protocols were formally defined through Rulemaking 18-12-005. BVES provided a PSPS plan update in on February 24, 2021, along with an updated Emergency Response Plan ahead of the 2021 WMP submission.[64] BVES determined PSPS susceptibility to directly impact customers when:

There exists the presence of extreme fire weather forecasts within the service area, and not solely based on county-wide Red Flag Warning issuances, and whereas these conditions meet set criteria threshold for initiating a PSPS activation.

Factors to activate PSPS include: design strength and characteristics of distribution overhead facilities, adjacent vegetation density, the National Fire Danger Rating System seven-day fire threat outlook, National Weather Service advisories, local weather forecasts, BVES's meteorologist's forecast, information received from BVES-owned weather stations, real-time information from trained personnel positioned in HFTD areas, and any other input received from public safety partners, the state, and local authorities.

Conditions of extreme fire weather that are forecasted outside of BVES's service area, and likewise do not meet service territory criteria thresholds. For this case, SCE would direct PSPS activation on SCE-owned and operated assets, which may lead to partial or complete loss of three service SCE supply lines into the territory.

In this situation, BVES would seek to supply power to its customers using all available resources, which include the Bear Valley Power Plant (BVPP) generating 8.4MW of local power that would supply critical facilities and the majority of the service area.

[64] BVES, Public Safety Power Shutoff Plan, February 24, 2021. https://www.bvesinc.com/media/managed/psps/BVES_INC_PSPS_Procedures_Rev1.pdf.

The table below outlines BVES's action plan for addressing partial or complete loss of power due to SCE supply line de-energization events.

Table 19: BVES Action for SCE Lines De-Energized due to PSPS

Condition	BVES Action
SCE De-energizes Doble or Cushenberry Line for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Energize Radford Line as needed to meet load demand. If the Utility Manager deems it necessary, energize the Radford Line as needed for reliability. Startup of the BVPP as needed to meet load demand. No reduction on load necessary, since the Doble and Cushenberry are capable of carrying the other's load. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines
SCE De-energizes Bear Valley Line for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If Radford is energized, shift loads to Shay Line prior to deenergizing for PSPS. Generally, this should be done about 4 hours prior to the SCE de-energizing the line. If needed, start up the BVPP to meet load demand. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines
SCE De-energizes Doble or Cushenberry and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Since the Doble and Cushenberry are capable of carrying the other's load, follow the procedure for "SCE De-energizes Bear Valley Line for PSPS" above. Prepare for potentially losing all SCE supply lines into BVES service area. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Doble and Cushenberry Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If not already done, energize the Radford Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, shift as much of the load to the BVPP and Radford Line as follows: Open the Shay and Baldwin automatic reclosers. "Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order. Start up the BVPP, place enginators on-line and increase load to within the combined capacity of the BVPP and Radford Line. Implement BVES Emergency Response Plan for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures. Prepare for sustained BVPP operations and rolling blackouts. Frequently monitor distribution circuit loads.
SCE de-energizes Doble, Cushenberry, and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If the Radford Line is energized, shift loads to the Shay Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, perform the following: Start up all of the BVPP enginators. Reduce system load to within the capacity of the BVPP by isolating distribution circuits as directed by the Field Operations Supervisor.

Condition	BVES Action
	Once system load is matched with the BVPP capacity, open the Shay and Baldwin automatic reclosers. Implement BVES Emergency Response Plan for sustained loss of all SCE supply lines including “rolling blackout” procedures.

Scope, scale, and frequency of PSPS activations will be mitigated through BVES’s seasonal operational posture that direct the following actions taken throughout the year:

4. The Radford Line is to be de-energized from April to October or else otherwise recommended by the Field Operations Supervisor. Re-energization can be achieved should the forecasted demand require additional generation, for planned maintenance, system upgrades, or other directed action. No redundancy degradation exists with this operational protocol since the supply lines from the Lucerne area are separated and independent of one another. The Radford Line assists to supply power during winter high load periods as BVES profiles as a winter-peaking utility.

5. From April to October, BVES will place certain auto-reclosers, fuse TripSavers, and switches in “manual” operation such that they will not shut and test upon detection of a fault. A specific list of switched mechanisms will be derived ahead of each fire season to ensure load forecasts align with present conditions to the best ability possible. The completion of the Grid Automation Project, which establishes connectivity and control of these devices, will necessitate a policy revision or re-evaluation.

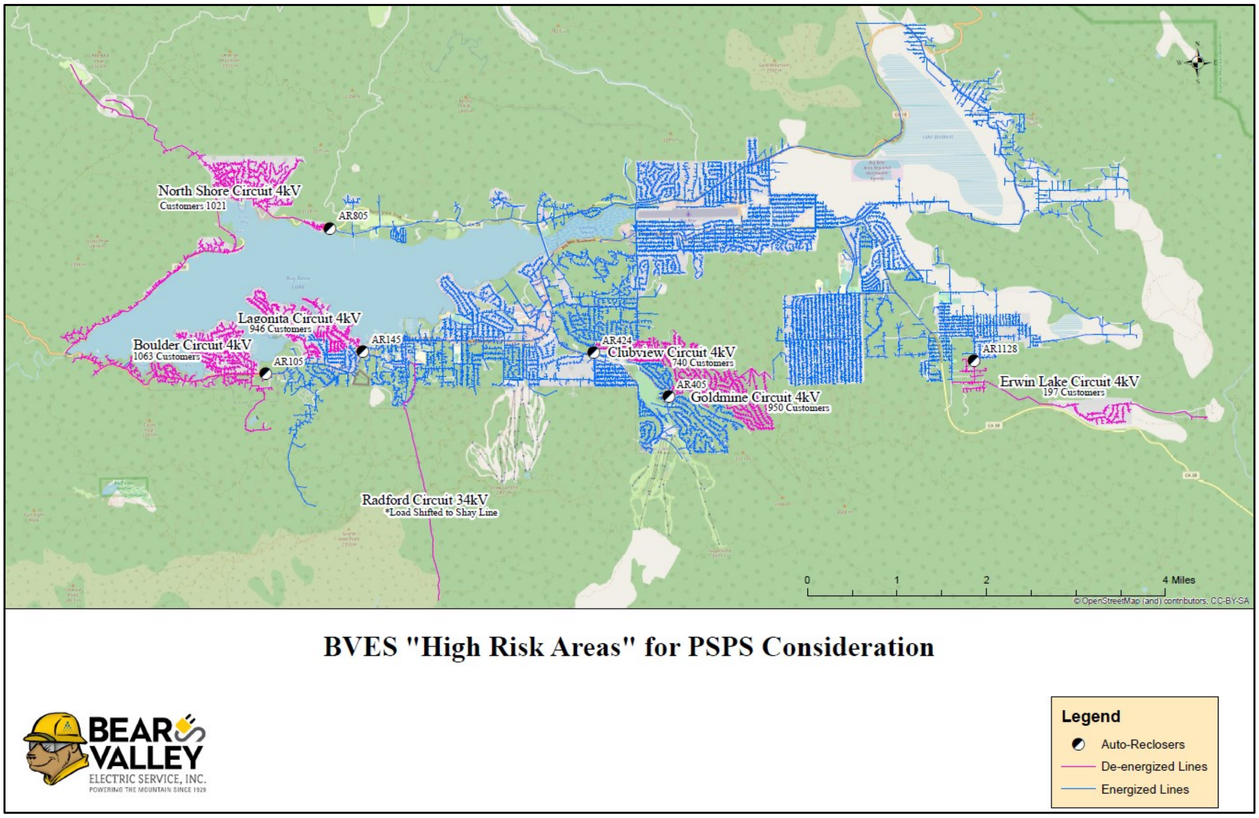
    a. When an auto-recloser, switch, or fuse TripSaver that was placed in “Manual” due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is “Green” or “Yellow,” the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk of causing fire.

6. Due to reduced load in non-winter period, the Utility Engineer & Wildfire Mitigation Supervisor will develop specific settings for auto-reclosers and other protective devices in the field to enhance fire prevention. The list of affected devices will be provided to the Utility Manager and the Field Operations Supervisor. Additionally, the Field Operations Supervisor will be provided the settings that the Field Operations staff will be required to set on each device. Specific dates to enter these reduced settings will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Engineering staff will not change device settings without the Field Operations Supervisor’s authorization.

It should be noted that while BVES is able to evaluate its facilities and determine the limiting wind speeds when distribution facilities are possibly at high risk, BVES is not able to determine the strength or health of vegetation surrounding bare conductors outside of the required vegetation clearance zones or other structures that may come loose and impact BVES distribution facilities. Therefore, BVES may determine a need to proactively de-energize facilities during high fire threat and high wind conditions. This would be done in close consult and coordination with local government and agencies. Isolating areas with switching devices allow for sectionalization of the areas affected, which will be communicated to affected parties if a decision to activate PSPS is made.

BVES has identified seven areas (six of which include customer impact) subject to proactive de-energization as well as the potential power loss to affected residents. This is illustrated in the map below. BVES estimates these outages to affect the number of customers during the worst-case conditions, and due to enhanced operational protocols and sectionalization design, minimal impact is expected in the event of a PSPS activation. It is presumed that only a “black swan” event would result in all areas being de-energized (i.e., SCE initiates the highest affected de-energization activation impacting supply lines and BVES lacks the ability to support base load due to unforeseen circumstances).

Figure 6: BVES High Risk Areas for PSPS Consideration



Recent PSPS Briefs and Initiative Mitigation Measures

In recent briefs to the WSD/OEIS in June 2021, BVES provided its action plans to monitor weather conditions, provide contextual information to customers regarding the potential of a PSPS activation, and efforts to reduce impact of a potential PSPS activation. This is summarized in the table below.[65]

Table 20: June 2021 PSPS Briefing Summary

Microgrids, Resiliency Zones, and Temporary Generation	Mitigation Measures to reduce need and/or impact of PSPS
Critical infrastructure already has backup generation and is outside PSPS high risk areas.	34.5 kV Supply Line re-closers have all been changed out to Pulse Conditioned IntelliRupters. (Completed in 2019)

[65] OEIS. 2021 Small Multi-Jurisdictional Utilities PSPS Briefing Workshop. June 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/documents/smju-2021-psps-preparedness-staff-briefing-1-presentation-final.pdf.

Microgrids, Resiliency Zones, and Temporary Generation	Mitigation Measures to reduce need and/or impact of PSPS
BVES in process of developing a small utility scale solar-battery project: Solar: 5 MW AC single-axis tracker solar generation facility. Battery: 4 MW/16 MWh lithium-ion NMC battery energy storage system	PSPS high risk areas sectionalized from rest of BVES system. (Completed in 2019)
Provide portable storage devices for access and functional needs or life support customers on an as needed basis	Covered conductor project in progress. Installed 7.7 circuit miles in 2020. Installed 1.4 circuit miles to date in 2021 of 12.9 circuit miles planned.
Customer Resource Center backup generation available	Eliminated all expulsion fuses from system.

A.15 Issues and Remedies for 2022 WMP

Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
BVES-21-01	Inadequate disaggregation of expenditure	As discussed in Section 1.2 of the Action Statement, BVES was required to disaggregate its WMP expenditure for its Revision Notice Response. However, Cal Advocates discovered that 17 of BVES's initiativeshave the same expense amount in 2020, 11 in 2021, and 13 in 2022. In response to a Cal Advocates' data request, BVES statesthat it spreads certain expenses equally across multiple initiatives, but BVES offers no quantitative analysis to support such allocation.	For its 2022 WMP Update, BVES must identify where common costs are allocated across multiple initiatives. In addition, BVES must justify its allocation methodology by describing these common costs in detail, explaining how theyrelate to each initiative anddemonstrating that the allocated values reasonablyreflect the initiatives' true costs.
BVES-21-02	Program targets are unmeasurable and difficult totrack	The 2021 WMP guidelines defines program targets as "quantifiable lists 86 program targets; 32 of thesetargets have no numerical target and 42 targets are quantified by the	In its 2022 WMP Update,BVES must: Only include quantifiable measurements of activity in its list of program targets in Table5.3-1 (or similar).

Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
		unmeasurable unit“Percent Project Milestones Completed” (or similar) measurements of activity.” In Table5.3-1: List and Description of Program Targets, Last 5 Years, BVES	To the extent possible, modify existing targets to use measurable units.For example, the unit for intrusive pole inspections should be “# of Pole Inspections” rather than “Percent of Scheduled Circuits Completed.” If using milestones as asign of progress, describe milestones in Section 7.3 under appropriate initiatives.
BVES-21-03	Vegetation inspection roles lack minimum forestry and arboriculture qualifications	None of the roles described in Supporting Table 5.4.1-1 include minimum qualifications in forestry and arboriculture. In contrast, Liberty and PacifiCorp require their vegetation inspection personnel to either have ISA Arborist Certification, be a Register Professional Forester, or have some arboriculture experience. EnergySafety is concerned that BVES does not hire qualified workers to conduct vegetation inspections.	BVES must: Provide evidence that its vegetation inspectionpersonnel are adequately qualified and trained to perform vegetation inspections. Include forestry and/or arboriculture certifications and/or experience as minimum qualifications for appropriate vegetationinspections roles.
BVES-21-04	No climatedriven risk mapping	BVES does not havea program that addresses climate- driven risk mapping.	In its 2022 WMP Update, BVES shall describe how itapplies risk analysis models to consider future climate projections.
BVES-21-05	Lack of consistency inapproach to wildfire risk modeling across utilities	The utilities do not have a consistent approach to wildfire risk modeling. For example, in their wildfire risk models, utilities use different types of data, use their individual data sets in different ways, and use different third-party vendors. The WSD recognizes that the utilities have differing service territory characteristics, differing data availability, and are at different stages in developing their wildfire risk models. However, the utilities face similar enough	The utilities must collaborate through a working group facilitated by Energy Safety to develop a more consistentstatewide approach to wildfire risk modeling. After Energy Safety completes its evaluation of all the utilities’ 2021 WMPUpdates, it will provide additional detail on the specifics of this working group. A working group to address wildfire risk modeling will allow for:

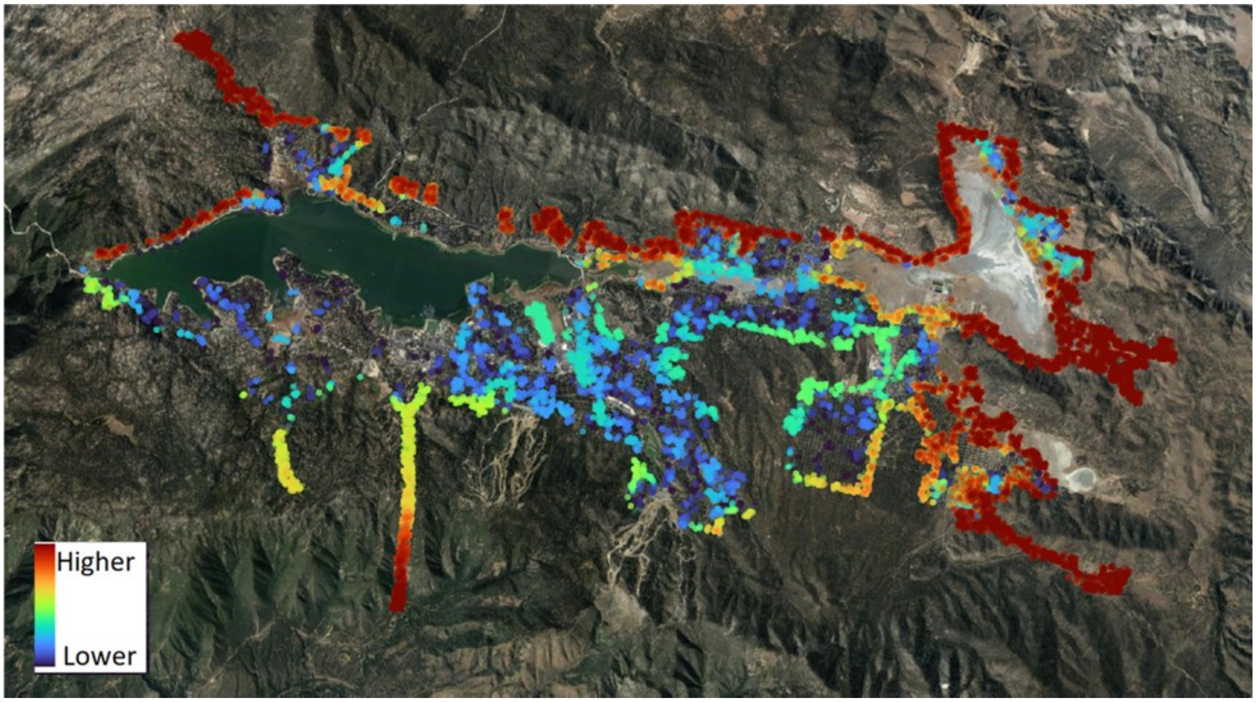
Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
		circumstances that there should be some level of consistency in their approaches to wildfire risk modeling statewide.	Collaboration among the utilities; Stakeholder and academic expert input; and Increased transparency.
BVES-21-06	Disparities between BVES's situational awareness and forecasting capabilities and maturity model reporting	BVES had a significant increasein its maturity assessment ratingsfor situational awareness and forecasting in its WMP update. Theratings are much higher in comparison to peer utilities and prior reporting in 2020. It remains unclear if the ratings selected are accurate representations of BVES's maturity, as the explanations in the initiatives do notexplain these improvements.	BVES must describe: How it intends to collect and measure physical impacts of weather on its grid, such as sway in lines and sway in vegetation. How it plans to includewind estimations at various atmospheric altitudes relevant to ignition risk. What initiative it has orhow it is using ignitiondetection software. How it plans to accurately forecast weather at least threeweeks in advance.
BVES-21-07	Lack of detailon prioritizationof initiatives based on determined risk	BVES does not provide any details on the actual prioritization of its grid hardening efforts, despite having determined the highest risk circuits along its system. Instead, BVES relies on the Tier 2 and Tier 3 HFTD designationsto justify prioritization. BVESfails to provide the details on how the timing of deployment of its grid hardening efforts mitigate its highest risk areas and fails to provide a plan that demonstrates it is addressing and mitigating its highest risk areas.	BVES must: Explain how the timingof deployment of its grid hardening efforts are based on its risk calculations and prioritize mitigating itshighest risk areas; and Provide a plan that demonstrates that BVES is addressing andmitigating its self- identified highest risk areas through system hardening initiatives.
BVES-21-08	Limited evidence to support the effectiveness of covered conductor	The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full	The utilities must coordinate to develop a consistent approach to evaluating the long- termrisk reduction and cost- effectiveness of covered conductor deployment, including: The effectiveness of covered

Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
		understandingof its long-term risk reduction and cost-effectiveness. The utilities' currentcovered conductor pilot efforts are limited in scope and therefore fail to provide a full basis for understanding how covered conductor will perform in the field. Additionally, utilities justify covered conductor installation by alluding to reduced PSPS risk but fail to provide adequate comparison to other initiatives' ability to reduce PSPS risk.	conductor in the field in comparisonto alternative initiatives. How covered conductorinstallation compares toother initiatives in its potential to reduce PSPS risk.
BVES-21-09	Lack of asset inspection quality assurance and quality control (QA/QC) program.	BVES is in the process of adopting a formal QA/QC program in 2021 butdid not provide dates on when it intends to implement such, did not provide details on its current informal QA/QC process, nor providedetails on the scope of the QA/QC program currently in development.	BVES must: Provide a timeline for its implementation of a formal QA/QC process. Explain how it conductsquality checks of its asset inspections prior to the adoption of the formal program. Develop an interim QA/QC procedure forasset inspections between now and the establishment of its newQA/QC program, if such has yet to be adopted, in order to ensure that work is being completed accurately and effectively. 4. Provide updates on the development of its QA/QC program in its Progress Report, including: (i) the scope of the QA/QC program, (ii) procedures of the QA/QC program that BVES has developed, and (iii) the status of theQA/QC program implementation.
BVES-21-10	Limited discussion ofcommunity	BVES-R7 requires BVES to discuss its community	BVES must: Provide descriptions ofnotification and

Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
	outreach	engagement and outreach as it relatesto VM in Section 7.3.5.1. BVES instead discusses fuels management activities performedby other entities including Big Bear Fire Department and Bear Valley Community Service District.25 BVES mentions outreach efforts to “USFS, CAL FIRE and Big Bear Fire Department in an effort to develop collaborative measures in the area of fuels management,” but fails to discuss how it mitigates the community impacts of major VM activities including tree-trimming and tree removal.	communication methods for customers and partner agencies regarding VM activitiesincluding, but not limited to, tree- trimming and tree removal. Detail any efforts in community outreachand public educationrelated to vegetation management.
BVES-21-11	Inadequate discussion of QA/QC of VM inspections	From the discussionin Section 7.3.5.13, itis difficult to know whether BVES has aQA/QC program for VM. A brief mention of third- party evaluations isthe only unequivocal detail. It is unclear whom at BVES performs QA/QC, how often QA/QC is performed, and what goals and targets exist for QA/QC.	BVES must: Describe the “lessons learned from third partyevaluations and inspections.” Provide the number of QA/QC evaluation andinspections completed each year. Provide a QA/QC audittarget as a percentage oftotal VM inspections per year. Detail BVES’s differentiation betweenits quality assurance program and quality control program. Report on BVES’s plan to add a QA program tothe current QC program.
BVES-21-12	Spatial dataissues	Energy Safety has identified numerousareas for improvement for BVES's Quarterly Data Reports. These issues negatively affect the usability of the data and do not meet Energy Safety GIS Standard.Energy Safety has specified these issues in	See Table 3 for specific remedies related to each data issue. In the November 1, 2021 report,BVES must report on its progress in advancing its GIS capabilities.

Utility-#	Issue title	Issue description	Remedies required and alternative timeline if applicable
		Table 3 of the Action Statement.	
BVES-21-13	Unexplained changes to risk spend efficiency (RSE)estimates for wildfire and PSPS mitigationinitiatives	In its 2021 Revised WMP Update, BVESreported six different RSE estimates for wildfire mitigation initiatives and four different RSE estimates for PSPS mitigation initiatives comparedto its 2020 WMP without explanation. Refer to Table 4 and Table5 for specific initiatives and RSE estimates.	BVES must provide all supporting documents andworkpapers to justify the changes in RSE estimates outlined in Table 4 and Table 5 of the Action Statement.
BVES-21-14	Limited discussion on reduction of scale, scope, and frequencyof PSPS	BVES has limited discussion on its near-term progress for reduction in scale, scope, and frequency of PSPS. BVES stated that due to its minimal use of PSPS in the past, it is unable to further reduce PSPS.Nevertheless, BVES must still report its plans to minimize PSPS scale, scope, and frequency, normalized for weather events andclimatic conditions.	BVES must report on its plan to minimize the scale, scope, and frequency of PSPS events normalized forweather events and climatic conditions, and fully describe how its planned mitigation initiatives minimize PSPS impact.

The responses below address the 14 issues identified in OEIS’s Final Action Statement on BVES’s 2021 WMP.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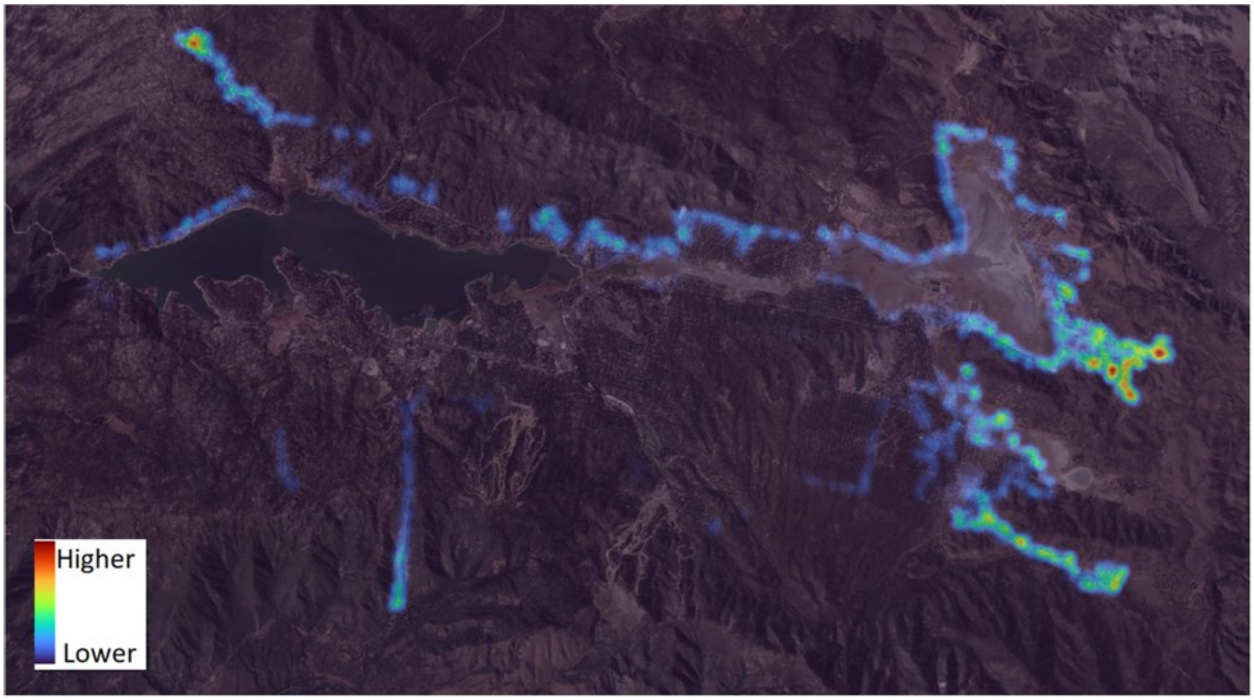
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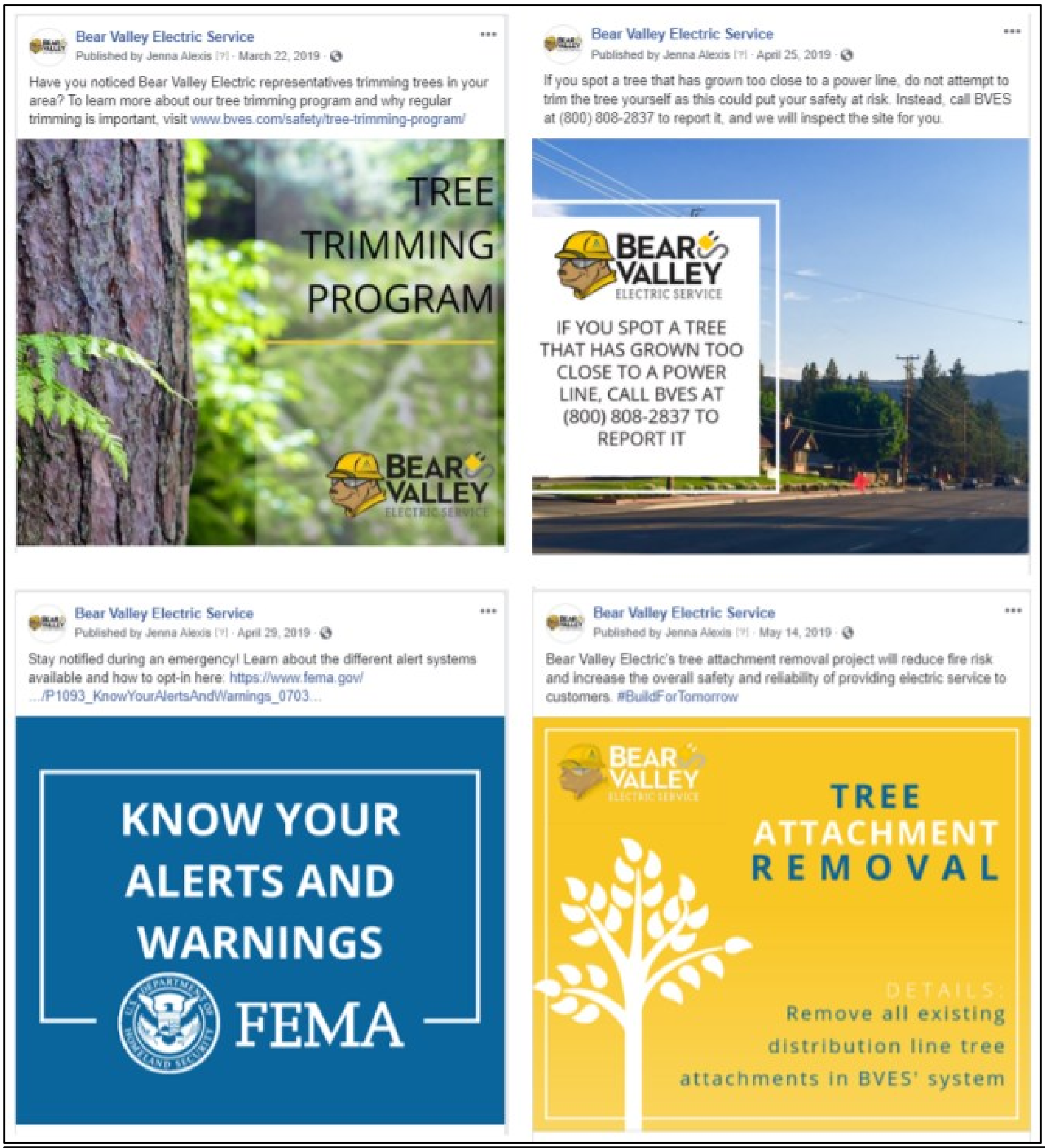
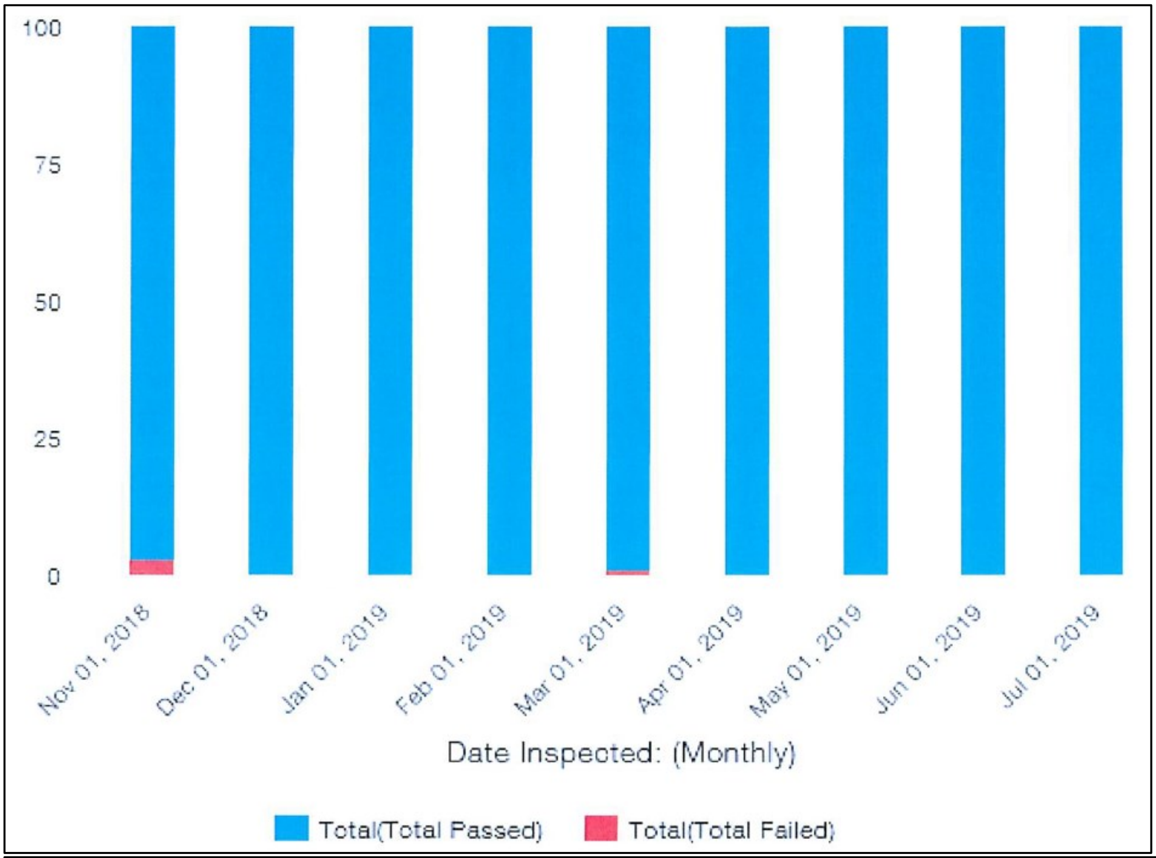


Table 1: Recent performance on progress metrics

Metric type	#	Progress metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021
2. Vegetation clearance findings from inspection - total	2.a.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition - total	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41
	2.a.ii	Number of spans insepcted for vegetation compliance - total	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029
2. Vegetation clearance findings from inspection - in HFTD	2.b.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition in HFTD	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41
	2.b.ii	Number of spans insepcted for vegetation compliance in HFTD	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029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Dec 01, 2018
Jan 01, 2019
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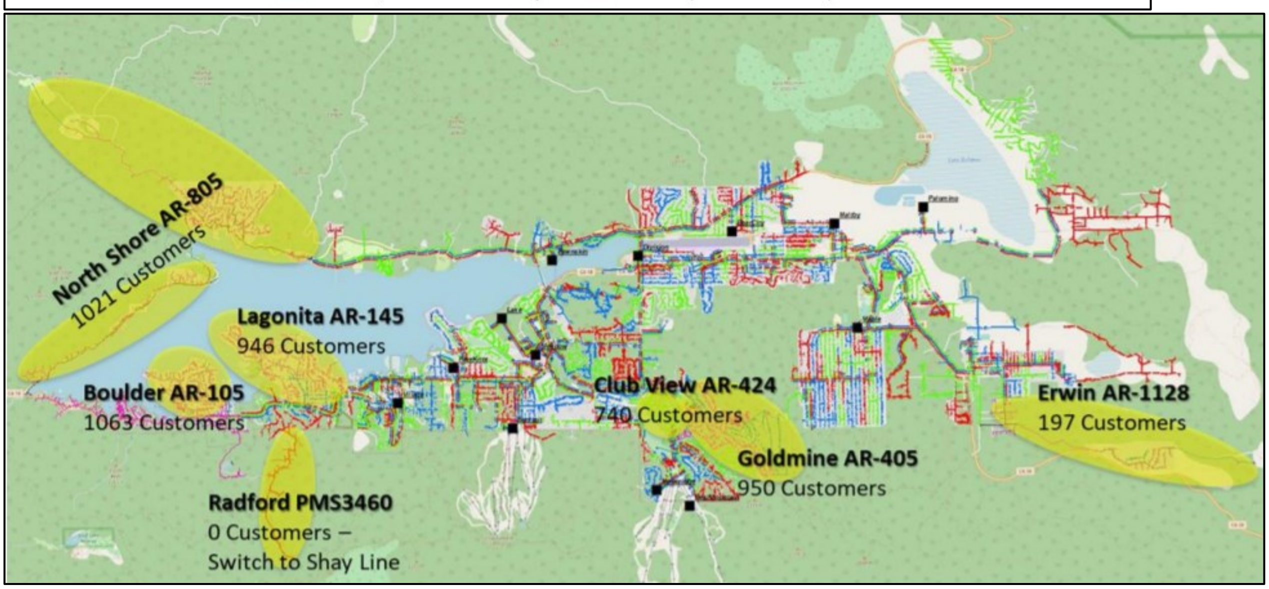
Mar 01, 2019
Apr 01, 2019
May 01, 2019
Jun 01, 2019
Jul 01, 2019
Date Inspected: (Monthly)
Total(Total Passed)
Total(Total Failed)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Lagonita AR-145
946 Customers
Boulder AR-105
1063 Customers
Club View AR-424
740 Customers
Erwin AR-1128
197 Customers
Goldmine AR-405
950 Customers
Radford PMS3460
0 Customers –
Switch to Shay Line

APPENDIX B. PUBLIC SAFETY POWER SHUTOFF PLAN

Bear Valley Electric Service, Inc. Public Safety Power Shutoff Plan

February 24, 2021

Approved by: ____
Paul Marconi, President, Treasurer & Secretary

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Purpose and Overarching Guidelines

Purpose of PSPS. The purpose of proactive de-energization is to promote public safety by decreasing the risk of utility-infrastructure as a source of wildfire ignitions. Generally, proactive de-energization will be referred to as Public Safety Power Shutoff (PSPS), which is consistent with the terminology used by the major California investor owned utilities.

Purpose of PSPS Plan. This document provides the policies and procedures of Bear Valley Electric Service, Inc. ("BVES") follows with regard to PSPS and addresses the following operational issues:

PSPS advance planning and preparations prior to the fire season.
Procedures leading up to, during, and following extreme fire threat weather events in which PSPS may be invoked. These include BVES's operational fire prevention actions and procedures.
Public outreach, coordination with local and government officials, advisory boards, public safety partners, representatives of people/communities with access and functional needs ("AFN"), tribal representatives (if applicable), senior citizen groups, business owners, and public health and healthcare providers including those with medical needs. This includes a Community Resource Center ("CRC") and communications regarding PSPS.

It should be noted that two other BVES documents provide information important to PSPS:

- ***BVES Emergency Response Plan***: Provides comprehensive outage management procedures, which are applicable to all outages including outages as a result of PSPS. The BVES PSPS Plan is designed to work in conjunction with the ERP and not duplicate existing procedures.
- ***BVES Wildfire Mitigation Plan***: Provides description of system hardening projects, operations and maintenance programs, and other initiatives being pursued by BVES to mitigate the need to execute a PSPS and/or to mitigate the impact of PSPS events. As these projects and programs are completed, this document will be updated as necessary to incorporate the improvements achieved.

Compliance. This documented includes requirements invoked by:

Safety and Enforcement Division Resolution, Electric Safety and Reliability Branch Resolution ESRB-8 8 of July 12, 2018: Resolution Extending De-Energization Reasonableness, Notification, Mitigation and Reporting Requirements in Decision 12-04-024 to All Electric Investor Owned Utilities.
California Public Utilities Commission Decision 19-05-036 of May 30, 2019: Guidance Decision on 2019 Wildfire Mitigation Plans Submitted Pursuant to Senate Bill 901.

California Public Utilities Commission Decision 19-05-040 of May 30, 2019: Decision on 2019 Wildfire Mitigation Plans of Liberty Utilities/CalPeco Electric; Bear Valley Electric Service, a Division of Golden State Water Company; and Pacific Power, a Division of PacifiCorp Pursuant to Senate Bill 901.
California Public Utilities Commission Decision 19-05-042 of May 30, 2019: Decision Adopting De-Energization (Public Safety Power Shutoff) Guidelines (Phase 1 Guidelines).
California Public Utilities Commission Decision 20-03-004 of March 12, 2020: Decision on Community Awareness and Public Outreach Before, During and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues.
California Public Utilities Commission Decision D20-05-051 of May 28, 2020: Decision Adopting Phase 2 Updated and Additional Guidelines for De-Energization of Electric Facilities to Mitigate Wildfire Risk.

Measure of Last Resort. BVES must only deploy PSPS as a ***measure of last resort*** and must justify why PSPS was deployed over other possible measures or actions. This plan provides courses of action to be taken leading up to possible PSPS such that an actual PSPS is the measure of last resort.

Customer Engagement. Customers and other impacted stakeholders should understand the purpose of PSPS, BVES's process for initiating it, how to manage safely through a PSPS event, and the impacts if deployed. To accomplish this, the BVES shall:

Develop and use a common nomenclature that integrates with existing state and local emergency response communication messaging and outreach and is aligned with the California Alert and Warning Guidelines.
Develop notification and communication protocols and systems that reach customers no matter where the customer is located and deliver messaging in an understandable manner.
Communicate to customers in different languages and in a way that addresses different access and functional needs using multiple modes/channels of communication.
Coordinate a Community Resource Center and work with local organizations.

PSPS Coordination. Deploying PSPS requires a coordinated effort across multiple state and local jurisdictions and agencies. Coordination in preparation for PSPS is a shared responsibility between BVES, public safety partners, and local governments; however, BVES is ultimately responsible and accountable for the safe deployment of PSPS. BVES must work with the California Governor's Office of Emergency Services to integrate its warning programs with the agencies and jurisdictions within California that have a role in ensuring that the public is notified before, during, and after emergencies. Throughout this document the collective phrase "Local Government, Agencies, and Partner Organizations" includes applicable local government and agencies, utilities, key non-government and commercial entities and also includes critical facilities and critical infrastructure. Further discussion is provided in Section 5.

BVES, emergency responders, and local governments need to be seamlessly integrated when communicating PSPS notifications, with the goal that local governments provide supplemental or secondary notifications in the near future given the primary or initial notification to the public provided by utilities. For now, BVES retains ultimate responsibility for notification and communication throughout a PSPS event.

BVES must coordinate with California Governor's Office of Emergency Services and the California Department of Forestry and Fire Protection to engage in a statewide public education and outreach campaign. The campaign must effectively communicate in multiple languages. The campaign must convey, in advance of wildfire season, the immediate and increasing risk of catastrophic wildfires and how to prepare for them, the impacts of PSPS, how the public can prepare for and respond to a PSPS event, what resources are available to the public during these events, what to do in an emergency, how to receive information alerts during a power shutoff, and who the public should expect to hear from and when.

PSPS Is an Emergency. Consequences of PSPS should be treated in a similar manner as any other emergency that may result in loss of power, such as earthquakes, floods or non-utility caused fire events. BVES must avoid development of duplicative or contradictory messaging and notification systems to those already deployed by first responders.

Reporting and Continuous Improvement. BVES must report on lessons learned from each PSPS event, including instances when PSPS protocols are initiated, but de-energization does not occur, in order to further refine PSPS practices.

BVES must work together with the other electric investor-owned utilities to share information and advice in order to create effective and safe PSPS programs at each utility and to ensure that utilities are sharing consistent information with public safety partners.

Chain of Responsibility

President is overall responsible for the PSPS Plan and ensuring it is properly implemented, resourced, trained upon, executed, and updated as appropriate. Furthermore, the President shall ensure proper communications and coordination with local government, agencies and customers.

Utility Manager is responsible for executing the BVES PSPS Plan to include:

Directing emergency operations per this plan and the Emergency Response Plan;
Ensuring that monitoring of weather forecasts and actual weather conditions is being properly conducted by appropriate staff per this plan;
Directing (or causing to be directed) the operational activities related to system line-up and PSPS as warranted;
Ensuring that Field Operations staff are providing timely and accurate information to the Customer Service Supervisor and/or other staff performing customer and public information functions;
Working closely and coordinating with counterparts at local government and agencies during the lead up to PSPS, during PSPS, and during restoration procedures and as necessary to achieve the fire prevention objectives of this plan;
Overseeing activation of the Wildfire Response Team (WRT) for PSPS procedures of this plan and determining the appropriate staff composition of the WRT when activated;
Training (or causing to be trained) BVES staff assigned to perform the various activities required by this plan;
Ensuring resources are available to properly execute this plan and identifying any gaps in resources to the President as well as proposed remedies;
Making all reports required by GO-166 and ESRB-8 to the applicable Commission Divisions;
Working closely with Regulatory Affairs staff to ensure this plan meets regulatory compliance requirements enacted by the Commission;
Reviewing and evaluating relevant data and documentation of inspections, patrols, operational system lineup, and PSPS activities; and
Evaluating at least annually, whether changes to this plan are warranted and implementing any necessary changes.

Field Operations Supervisor is responsible for directing operations in the field to include:

Monitoring (or causing to be monitored) weather advisories, consultant forecasts, and the NFDRS forecast frequently and at least daily;
Directing and managing operational system line-ups based on conditions as described in this plan;
Directing and managing PSPS procedures of this plan;

Directing the activities of the WRT;
Controlling all switch and system lineup operations;
Providing (or causing to be provided) timely and accurate information to the Customer Service Supervisor and/or other staff performing customer and public information functions;
Informing the Utility Manager of any system degradations;
Collecting relevant data and maintaining documentation of inspections, patrols, operational system lineup, and PSPS activities; and
Submitting to the Utility Manager recommended changes to this plan as warranted and at least annually.

Utility Engineer & Wildfire Mitigation Supervisor is responsible for fire prevention planning and engineering design of the electric distribution, sub-transmission and substations to include:

Ensuring system design and construction is in compliance with applicable government rules and regulations to mitigate fire;
Developing distribution, sub-transmission and substations designs that would enhance fire prevention;
Researching, evaluating, and sourcing materials that would enhance fire prevention;
Developing device protective settings and selecting fuses that enhance fire prevention while taking into account the served load demand;
Supporting Field Operations and the WRT as directed by the Utility Manager in the execution of system operations per this plan; and
Submitting to the Utility Manager recommended changes to this plan as warranted and at least annually.

Customer Program Specialist under the supervision of the Customer Service Supervisor and the Energy Resource Manager is responsible for the BVES Communications Plan to include:

Making (or causing to be made) local government, agency, and customer notifications per this plan;
Ensuring pre-planned statements are PSPS related notifications per this plan;
Establishing and maintaining customer communications methods, systems, and equipment to support proactive de-energization notifications per this plan;
Training staff assigned to perform customer and public information functions on generating customer and media notification statements and utilizing the customer communications methods, systems, and equipment;
Developing (or causing to be developed) the contact list of local government and agencies per this plan;
Directing a customer education strategy to inform customers about BVES's fire mitigation programs, policies and procedures including PSPS; and
Submitting to the Utility Manager recommended changes to this plan as warranted and at least annually.

BVES Specific Background Information

Service Area Description and Environment. Bear Valley Electric Service is a small electric utility, located in the mountain resort community of Big Bear Lake, California, that provides service to approximately 24,500 customers in a 31-square mile service area. BVES owns and operates 87.8 miles of overhead 34.5 kilovolt sub-transmission miles, 2.7 miles of 34.5 kilovolt underground sub-transmission miles, 488.6 miles of overhead distribution circuit miles, 89.1 miles of underground distribution circuit miles, 13 sub-stations and a natural gas-fueled 8.4 MW peaking generation facility. The BVES service area is rural and mountainous and is served predominantly from bare wire overhead facilities. BVES's entire service area is under the jurisdictional responsibility of the City of Big Bear Lake and some areas (unincorporated) under the responsibility of the County of San Bernardino. The San Bernardino Mountains and forests are managed by the United States Forest Service, California Environmental Protection Agency, and the California Department of Fish and Wildlife.

Since the service territory is entirely above 3,000 feet, all construction is required to conform to "heavy" loading standards of GO-95. In addition, the high elevation provides for a beautiful alpine, heavily treed, mountainous environment that is vulnerable to wildfires. The entire service area is within the High Fire-Threat Districts and has areas designated as Tier 2 and Tier 3 per GO-95 Rule 21.2. Additionally, some of BVES's service area overlap with the Zone 1 per GO-95 Rule 21.2. Therefore, all construction, inspection, vegetation management, and emergency planning must also conform to the High Fire-Threat District requirements of GO-95, GO-165, and GO-166.

Bear Valley serves as a desirable vacation destination during the winter months due to the local ski resorts and winter activities. This creates a winter peaking environment that is enhanced by local snow making activity during the late evening hours. After the normal winter months, the population and load profile dramatically change. Understanding the local load profile is one key element to designing a successful fire prevention strategy.

Susceptibility to PSPS. The BVES service area is susceptible to several conditions in which PSPS would have a direct impact to its customers. These are:

Extreme fire threat weather and conditions in BVES's service area that warrant BVES to implement PSPS on BVES owned and operated power lines in some or all areas of its service area.

Extreme fire threat weather and conditions outside of the BVES's service area, in which Southern California Edison (SCE) directs PSPS on SCE owned and operated power lines leading to a partial or complete loss of the three SCE supply lines into the BVES service area. Note that it is very possible that the extreme fire threat weather and conditions causing SCE to de-energize its supply lines to BVES may

not exist in the BVES service area. In this case, BVES would seek to supply power to its customers using all available power resources.
Combination of the above, PSPS is warranted in some or all areas of the BVES service area and SCE has implemented PSPS actions that result in a partial or complete loss of supplies to the BVES service area.

BVES Fire Prevention Procedures

Fire Prevention. Because PSPS is an operational safety measure of last resort, it is logical that the PSPS Plan include BVES's operational fire prevention plan measures so that the progression of operational steps to be taken by BVES staff is properly sequenced and understood by all stakeholders.

Ordering Paragraph 5 of D.12-01-032 required BVES to prepare a Fire Prevention Plan to identify the occurrence of 3-second wind gusts that exceed the structural and mechanical design standards for overhead power-line facilities. D.14-05-020 modified D.12-01-032 by eliminating the requirement to identify 3-second wind gusts in real time, provided a utility will still address the situation when all three of the following conditions occur simultaneously: (i) 3-second wind gusts exceed the structural or mechanical design standards for the affected overhead power-line facilities, (ii) these 3-second gusts occur during a period of high fire danger, and (iii) the affected facilities are located in a high fire-threat area. D.14-05-020 also required utilities to identify the specific parts of their service territories where all three conditions listed in Ordering Paragraph I (a) occur simultaneously, based on a minimum probability of 3% over a 50-year period that 3-second wind gusts which exceed the design standards for the affected facilities will occur during a Red Flag Warning in a high fire-threat area. Ordering Paragraph 2 of D.17-12-024 requires each electric investor-owned utility have a fire prevention plan for facilities in the High Fire-Threat District containing the information specified in General Order ("GO") 166, Standard 1, Part E, to the extent applicable to the electric utility's service area and to file a report containing the fire prevention plan annually beginning October 31, 2018.

In accordance with D.12-01-032, D.14-05-020, D.17-12-024, and GO-166, this plan lists and describes the operational fire prevention measures BVES intends to implement to mitigate the threat of power-line fires generally and in the situation where all three of the conditions listed in GO-166, Standard 1, Part E occur simultaneously. BVES has identified areas that could be susceptible to these conditions. These areas are heavily forested, abundant in available fuel and could threaten the system when high winds occur. When these conditions exist, BVES has pre-identified areas that are targeted for PSPS in Appendix B.

Note that as previously stated, BVES's Wildfire Mitigation Plan provides descriptions of system hardening projects, operations and maintenance programs, and other initiatives being pursued by BVES to mitigate wildfire. Therefore, the PSPS Plan in conjunction with the Wildfire Mitigation Plan satisfy BVES's Fire Prevention Plan compliance requirements.

The fire prevention plan is intended as a starting point. As system improvements are made and environmental conditions change, the plan will evolve to meet these changes. In creating the plan, BVES has incorporated the input and interests of our stakeholders to ensure that the needs of the community are effectively met while mitigating the risk of wildfire. Community outreach and communications are a key component of this plan as well as maintaining partnerships with the Big Bear Valley Mountain Mutual Aid Association, City of Big Bear Lake, San Bernardino County, Big Bear Fire Department, Big Bear Lake Sheriff’s Department, other local agencies, local utilities, local radio stations, news media, and the public.

Wildfire Mitigation Strategy. BVES’s approach to mitigating wildfire is described in its Wildfire Mitigation Plan (WMP) and is a comprehensive mitigation strategy focused on five principal functional areas to enhance public safety:

Design & Construction: This strategy is discussed in BVES’s WMP and is designed to provide effective long-term mitigation solutions that reduce the likelihood of wildfire and also reduce the reliance on other short-term wildfire mitigation measures that have an adverse impact on customers, such as PSPS.
Inspection & Maintenance: This strategy, also detailed in BVES’s WMP, is designed to provide effective wildfire risk mitigation where system Design & Construction fall short. For example, where bare conductor is employed, the vegetation management program is essential to mitigating wildfire risk.
Situational & Conditional Awareness: This strategy, detailed in BVES’s WMP, is designed to provide decision makers and Field Operations staff critical information so that operational decisions are made on the most accurate information available. Additionally, collecting metrics overtime provide a better picture of the wildfire risk drivers and inform Design & Construction and Inspection & Maintenance strategies.
Operational Practices: This plan mostly focuses this strategy but it is also discussed in the WMP. The Operational Practices strategy is designed to provide effective wildfire risk mitigation where system Design & Construction, Inspection & Maintenance, and Situational & Conditional Awareness fall short. For example, Line crews are required by BVES’ procedures to perform circuit patrols during high fire threat conditions upon restoration from outages on circuits with bare conductor.
Response & Recovery: This strategy is designed to provide BVES’s plan to respond to wildfires and following wildfires regardless of how the wildfire started.

Operational Practices. This plan focuses on the operational practices to mitigate the need for PSPS so that PSPS is ultimately the measure of last resort during extreme fire threat weather conditions. The following operational tools, which will be discussed further in this procedure, are available to be utilized as conditions warrant and should be exhausted before PSPS is employed (these are not listed in order of priority):

Set automatic reclosing devices to Manual.
Set electronic fuses (TripSavers) to Manual.
Adjust system lineup.
Conduct circuit patrol when circuit protective device trips for an unknown cause prior to re-energization.

Have Service Crew and Field Inspector patrol service area focusing on high risk areas.
Deploy wildfire Response Team(s) to high fire risk areas.
Adjust protective device settings optimized for fire prevention.
Increase frequency of consultant meteorologist forecast.
Increase monitoring of weather stations, forecasts, and fire threat conditions.
Increase communications with Southern California Edison points of contact.
Proactively engage with first responders, local government and agencies, and other stakeholders.
Proactively communicate with customers and other stakeholders.
Identify Medical Baseline customers and Access and Functional Needs populations that may be impacted.
Prepare to activate Community Resource Center.
Activation of Emergency Operations Center and Emergency Response Plan.
Prepare Bear Valley Power Plant for sustained operations.
Conduct switch operations to minimize impact of potential PSPS activity.
Engage temporary generation.
Activate Community Resource Center.

Condition Based Operational Measures. BVES's operational measures to prevent fire are condition based to ensure the BVES system is optimized for wildfire mitigation, public safety, and reliability. There are two specific levels of conditions in the BVES service area that are considered when determining the appropriate operational measures to be implemented:

Seasonal Considerations: Provide a high level operational system lineup and operating guidance to Field Operations crews.
Daily-to-Real-time Considerations: Provide granular operational system lineup and operating guidance to Field Operations crews based on specific forecasts of the weather and fire threat conditions and current system degradations, which may be due to maintenance activities and/or known equipment and/or facilities failure or degradation. Daily-to-Real-time considerations always override seasonal considerations. For example, having high fire threat weather conditions in January is not common, but possible; therefore, in this case, system and operational guidance would be optimized to prevent wildfires.

Seasonal Considerations. Understanding BVES's system demand, service area environmental factors, and wildfire risk drivers allows BVES to operate the system in a manner that is optimized for public safety including wildfire mitigation, reliability, and increased quality of service delivered. The winter months (November through March) bring the following characteristics to BVES's service area:

Heaviest load demand due to increased tourism and ski resort snowmaking;
Low ambient temperatures that frequently go below freezing; and

Lower wildfire risk due to snow and higher moisture content in the service area.

When electric power is not available for any reason combined with freezing temperatures, the situation is an even greater public safety concern. Therefore, BVES needs to recognize that under these conditions, system reliability and continuity of electric service is important to public safety and every effort should be taken to restore power in a safe and timely manner.

The non-winter months (April through October) bring the following characteristics to BVES's service area:

Lower load demand due to reduced or minimal tourism and no ski resort snowmaking, therefore BVES's load is generally lowest in April, May, September, and October; the load increases somewhat in the summer months of June, July, and August;
Higher ambient temperatures with low humidity that rarely require air conditioning; and
Higher wildfire risk due to low moisture content in the service area and increase presence of fuel (dry vegetation).

Therefore, during the winter months as described above, the BVES distribution system is optimized for safety and reliability. Following the winter season, the system operational focus is more defensive and optimized almost entirely for fire prevention.

Daily-to-Real-time Considerations. The daily and even hourly changes in environmental and system conditions can change the risk of wildfire significantly. Therefore, the factors affecting Daily-to-Real-time considerations must be understood and be evaluated by the Operations Team to develop the appropriate risk mitigation package on a daily or even more frequently when adverse factors develop or are expected to develop. Some the factors that the Operations Team needs to consider are:

Forecasted and actual weather: Sustained wind speed, wind gust strength, dryness (humidity), precipitation, etc.
Fuel inventory: Buildup of ground cover vegetation, timber on the ground, thickness of forest, etc.
Dryness of fuel: Dryness of dead vegetation, timber on the ground, etc.
System design limitations: Installed bare conductor configuration, conventional expulsion fuses installed in the system, switches with limited protective and remote control capabilities, etc.
T&D equipment failure or degradation: Protective switch failure, loss of remote connectivity with protective devices, etc.

Missed or delayed inspection: Detailed inspection or patrol per GO-95 missed or delayed, GO-174 inspection missed or delayed, other inspection deemed critical missed or delayed, etc.
Delayed correction of fire hazard inspection discrepancies: Correction of "must be fixed before fire season" discrepancies, GO-95 discrepancies not corrected within required periodicity, etc.
Operational deviations from normal lineup: Abnormal system lineup due to planned maintenance, system upgrades, equipment degradation, etc.
Degradation in situational awareness: Failure or loss of connectivity with installed weather stations, loss of NFDRS (e.g., during Federal Government shutdown), loss of remote circuit monitoring, loss of HD Alert Camera coverage, etc.
Resource degradation: Insufficient line crews and/or other key operation staff, loss of utility vehicles, etc.

Therefore, for obvious reasons and as previously stated **Daily-to-Real-time considerations always override seasonal considerations**.

Pre-Planned Operational Posture. Some of the factors discussed in the previous section, may have a determined utility condition based response posture, while others require the specific evaluation by the Operations Team of the particular issue. The operational actions to be taken for forecasted and actual weather, fuel inventory, dryness of fuel, and system design limitation consideration factors are easily pre-determined. Whereas the response to the rest of the Daily-to-Real-time consideration factors, must be individually evaluated to determine their impact on the overall plan. For example, if certain weather stations suffer a failure, the Utility Manager may require the Wildfire Response Team be deployed sooner in a high wind developing situation.

Seasonal Operational Posture: The following operational actions are to be taken as follows:

The Radford Line will be de-energized from April to October. Specific dates will be recommended by the Field Operations Supervisor and approved by the Utility Manager. The line will be ready for re-energization should the load demand require it, for planned maintenance or system upgrades, or for other operational reason approved by the Utility Manager. De-energizing the Radford Line does not degrade redundancy since the supply lines from Lucerne are separate and independent of each other. The Radford Line is simply needed to assist with winter high loads. The Utility Manager will inform the President of any changes in the status of the Radford Line.
From April to October, certain Auto-Reclosers and Switches shall be placed in "Manual" (e.g., they will not shut and test upon detecting a fault). The Field Operations Supervisor will develop a specific list of the devices to be placed in

"Manual" and will forward the list to the Utility Manager and President. Specific dates will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Once BVES's Grid Automation Project establishes connectivity and control of these devices, this policy will be re-evaluated.
From April to October, all Fuse TripSavers shall be placed in "Manual" (e.g., they will not shut and test upon detecting a fault). Specific dates will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Once BVES's Grid Automation Project establishes connectivity and control of these devices, this policy will be re-evaluated.
Due to reduced load in non-winter period, the Utility Engineer & Wildfire Mitigation Supervisor will develop specific settings for Auto-Recloser and other protective devices in the field to enhance fire prevention. The list of affected devices will be provided to the Utility Manager and the Field Operations Supervisor. Additionally, the Field Operations Supervisor will be provided the settings that the Field Operations staff will be required to set on each device. Specific dates to enter these reduced settings will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Engineering staff will not change device settings without the Field Operations Supervisor's authorization.
When an Auto-Recloser, Switch, or Fuse TripSaver that was placed in "Manual" due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is "Green" or "Yellow," the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk of causing fire.

Daily-to-Real-time Operational Posture: The pre-planned operational postures provided in this section take into account the System Design Limitations factor. As system hardening and other Wildfire Mitigation Plan projects and programs are completed thereby mitigating the risk to wildfire, the Utility Manager will recommend updates to the plan.

BVES's forecasting framework for fire prevention measures relies on the National Fire Danger Rating System (NFDRS) and contracted meteorologist evaluation of the local forecast. The entire BVES system is in NFDRS Predictive Service Area SC10. The predictive service provides a wildfire risk forecast based on weather, on fuel build up, and fuel dryness among other factors and designates high-risk days as indicated in Table 4-1, Fuel Dryness and High-Risk Days, below:

Table 4-1: Fuel Dryness and High-Risk Days

Fuel Dryness &	Rating	Description

High Risk Days		
Green	Moist	Little to no risk of fires.
Yellow	Dry	Low risk of large fires in the absence of a “High Risk” event.
Brown	Very Dry	Low/moderate risk of large fires in the absence of a “High Risk” event.
Orange	High-Risk Day	At least a 20% chance of a “Large Fire” due to a combination of either “Dry” or “Very Dry” fuel dryness and a critical burn environment (e.g., Santa Ana winds).
Red	High-Risk Day	At least a 20% chance of a “Large Fire” due to a combination of either “Dry” or “Very Dry” fuel dryness and an ignition trigger (lightening).

An example of the seven-day forecast is provided below in Table 4-2, Example NFDRS Forecast:

Table 4-2: Example NFDRS Forecast

SC09-Western Mountains							
SC10-Eastern Mountains							
SC11-Southern Mountains							

The NFDRS is generally updated 3-5 times per day. Additionally, it should be noted that it has been observed that during the Federal Government shutdowns due to budget issues, the NFDRS forecast is suspended. Therefore, during these periods, the Utility Manager must recommend measures to mitigate this degradation in situational awareness.

The contracted meteorologist integrates the NFDRS with the detailed local forecast specific to BVES's service area and develops a risk rating as indicated below in Table 4-3, Significant Fire Potential.

Table 4-3: Significant Fire Potential

The Field Operations Supervisor will monitor the fire risk as designated by the consultant meteorologist, the NFDRS fire danger forecast, and indications from installed weather stations, which are equipped with alarms based on actual wind speed and then direct the proper operational pre-planned response. As indicated in Table 4-4 below, "Brown", "Red", and "Orange" are considered elevated fire threat conditions that require the BVES system to be configured for fire prevention over reliability concerns.

Table 4-4: Operational Direction Based on Wildfire Risk Forecast

Operations Pre-Planned Action	Green	Yellow	Brown	Orange	Red
Auto-Reclosers and Protective Switches with Reclosing Capability[1]	Automatic[1]	Automatic[1]	Manual (Non-Automatic)		
Patrol following circuit or feeder outage[2]	No[2,3]	No[2,3]	Yes		
Fuse TripSavers[1]	Automatic[1]	Automatic	Manual (Non-Automatic)		
Radford Line Use[4]	May be energized	May be energized	De-energize[5]	De-energize	De-energize
Deploy Wildfire Risk Team(s) to "high risk" areas	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Forward to Field Operations updated list of medical baseline customers and impacts access and functional needs population	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Activate EOC	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Prepare Bear Valley Power Plant for sustained operations.	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Conduct switching operations to minimize impact of potential PSPS activity	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.		
Activate first responder, local government and agency, customer	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual		

and community, and stakeholders PSPS communications plan			sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.
Activate Community Resource Centers	No	No	Yes, if forecasted sustained wind or 3-second wind gusts expected to exceed 55 or actual sustained wind or 3-second wind gusts exceed 45 mph and expected to increase.
Public Safety Power Shutoff	No	No	Yes, if actual sustained wind or 3-second wind gusts exceed 55 mph.[6]

[1] During the non-winter months, certain devices as developed by the Field Operations Supervisor and approved by the Utility Manager will remain in Manual (Non-Automatic) for the entire period regardless of the wildfire risk.
[2] During the non-winter months, when an Auto-Recloser, Switch, or Fuse TripSaver that was placed in "Manual" due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is "Green" or "Yellow," the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk to causing fire.
[3]No patrol is required. Re-test allowed following check of fault indicators, SCADA, other system indicators, and reports from the field. If the re-test fails, a patrol is mandatory.
[4] Normally only energized during winter period. If must be de-energized during winter period due to high risk conditions, and load is beyond the capability of the Lucerne supply lines plus the BVPP capacity, then reduce interruptible customer load as needed.
[5] May be energized if forecasted and actual sustained wind and wind gust conditions are less than 40 mph and the Radford Line is required to meet load demand or the support load due to loss of other power sources or due to planned maintenance when the benefits of the maintenance will overall reduce the risk of wildfire. In all of these cases, the Utility Manager will approve energizing the Radford Line and will inform the President.
[6]The Utility Manager may initiate PSPS if in his judgement the actual conditions in the field pose a significant safety risk to the public.

Public Safety Power Shutoff (PSPS) Consideration. Based on the evaluation of BVES's potentially weakest overhead facilities, BVES has determined that specific actions per Table 4-4 above should be taken when wind gusts of 3 seconds or more exceed 55 mph and a period of high fire threat danger exists. These conditions are often referred to as "extreme fire threat weather and conditions." This action is designed to satisfy GO-166 Standard 1.E requirements.

Despite having a proactive and aggressive vegetation management program, vegetation may still contact power lines; for example, in high winds, branches outside the vegetation clearance zone may break and be blown onto bare conductors and/or trees outside the clearance zone may fall into bare conductors. The specific strength of trees and branches is unknown; therefore, in high winds, it is impossible to predict how every tree and branch in the service territory would be impacted. This condition plays a key role how BVES has selected its tripwire 3-second wind gust speed for PSPS and designated certain locations as "at risk" locations for proactive de-energization during extreme fire weather conditions.

Changes in vegetation density, circuit improvements such as conversion from overhead to underground, or other environmental factors may drive BVES to re-evaluate the designated "at risk" line sections in its system and, therefore, specific line sections may be added, removed or modified to the "at risk" list as appropriate in the future.

It should be noted that while BVES is able to evaluate its facilities and determine the limiting wind speeds when distribution facilities are possibly at high risk, BVES is not able to determine the strength or health of vegetation surrounding bare conductors outside of the required vegetation clearance zones as well as other structures that may come loose and impact BVES distribution facilities. Therefore, BVES may determine a need to proactively de-energize facilities during high fire threat and high wind conditions. This would be done in close consult and coordination with local government and agencies.

In determining whether to invoke PSPS, BVES staff considers a number of factors affecting whether or not "extreme fire weather and threat conditions" exist including the following:

Design strength and other characteristics of distribution overhead facilities.
Vegetation density.
National Fire Danger Rating System (NFDRS) for 7-day fire threat outlook.
National Weather Service advisories.
Local weather forecasts and advisories.
BVES meteorologist's forecast.
Information from BVES installed weather stations.
Real-time information from trained personnel positioned in high-risk areas.
Input from state and local authorities and Emergency Management Personnel.

"Extreme fire weather conditions" are deemed to be forecasted or exist when the National Fire Danger Rating System forecast is "red," "orange," or "brown" for area SC-10, high winds (45 mph or greater) are forecasted or measured, and the BVES meteorologist forecasts high fire threat conditions.

Once it is determined that "extreme fire weather conditions" are forecasted or exist, BVES Staff will implement BVES Public Safety Power Shutoff Procedures per Section 4 at the direction of the Utility Manager.

BVES has identified seven sections of "at risk" areas based on the type of distribution facilities (overhead bare conductions, high voltage, etc.), tree and vegetation density, available dry fuel, and other factors that make certain locations more vulnerable to wildfire risk. As previously stated, BVES's entire service area is in the High Fire Threat District (HFTD) Tiers 2 and 3. The "at risk" areas are identified shown in Appendix A map. These areas may be selectively de-energized by "opening" the Auto-Reclosers (AR) designated in Table 4-5, Switches to De-energize "At Risk" Areas, below.

Table 4-5: Switches to De-energize "At Risk" Areas

Circuit (AR To Be Opened)	Number of Customers
Radford 34kV	0[1]
North Shore 4kV (Open AR) 805)	1021

Erwin 4 kV (Open AR 1128)	197
Boulder 4kV (Open AR 105)	1063
Lagonita 4kV (Open AR 145)	946
Club View 4kV (Open AR 424)	740
Goldmine 4kV (Open AR 405)	950

[1]Load is shifted to Shay 34kV line.

It is expected that if PSPS is necessary, in most cases it would be limited to one or more of these “high risk” areas. However, the Operations Team must monitor the entire service area and invoke PSPS as a measure of last resort on any BVES circuit when condition warrant such action.

Restoration from PSPS. When wind speeds in the affected area where PSPS was invoked calm below 50 mph for a minimum period of 20 minutes, crews may assess the fire weather conditions have subsided to “safe levels.” However, the crews may extend the calm period beyond 20 minutes, if they assess that further gusts of greater than 50 mph are likely based on their direct observation of local conditions or forecasts indicate a high probability of winds picking up to greater than 50 mph. Crews should communicate with the Field Operations Supervisor prior to assessing the situation as “safe levels” so that an evaluation of actual conditions in the field may be merged with the latest forecasted information. Restoration activities include:

Validating that the extreme fire weather conditions have subsided to safe levels.
Conducting field inspections and patrols of facilities that were de-energized.
Re-energization of inspected (and repaired if necessary) circuits.

BVES PSPS Procedures

Emergency Response Plan. Section 4 to the BVES Emergency Response Plan provides an explanation of the BVES system sources of power and actions to be taken when there is partial or complete loss of sources of power. Appendix B to this Plan provides a graphic showing the sources of power available to the BVES system including the SCE supply lines and their capacity. This PSPS Plan provides supplemental guidance in the case of SCE PSPS events that result in a complete or partial loss of all SCE lines in order to avoid a "black start" of the Bear Valley Power Plant (BVPP). Once PSPS is implemented, outages shall be managed using the guidance of the BVES Emergency Response Plan and the supplemental guidance of this procedure.

PSPS Phases. Table 5-1, PSPS Phases for PSPS Procedures, provides a time-line summary of actions to be taken for PSPS on BVES owned bare wire overhead power lines in some or all areas of the BVES service area and/or SCE directed PSPS affecting the BVES service area. It should be noted that weather changes can be sudden and the target timelines may end up being shorter than indicated in Table 5-1. PSPS actions are to be driven by forecasts and actual conditions in the field. The specific phases are:

Preparatory Phase: Conducted annually well before extreme fire threat conditions are expected; or when lessons learned or other conditions warrant updating plans, training, and/or outreach. Develop communication and notification plans jointly with CalOES, county and local governments, independent living centers, and representatives of people/communities with AFN. Create a plan for CRC(s).
Warning Phase: Starts 4-7 days prior to forecasted extreme fire threat weather and conditions. Mainly involves preparing to conduct PSPS when it is warranted and notifying local government, agencies, partner organizations, and customers. This phase includes various levels of notification at the 4-7 days ahead, 4 days ahead, 2-3 days ahead, 1-2 days ahead, and 1-4 hours ahead (PSPS imminent) points in the preparatory process.
Implementation Phase: Involves de-energizing "at-risk" areas due to verified actual extreme fire threat weather and conditions and/or responding to SCE directed PSPS of SCE supply lines to BVES service area.
Restoration Phase: Involves restoring power to de-energized circuits following verification that actual extreme fire threat weather and conditions have subsided and/or restoring SCE supply lines when they are re-energized.
Reporting and Lessons Learned Phase: Documenting and reporting to Safety Enforcement Division required information on the PSPS event and capturing lessons learned to ensure future PSPS events benefit from an understanding of what worked and what did not work in previous PSPS events.

PSPS Procedures. Section 4 (Fire Prevention) provides the operational guidance on actions to be taken to mitigate the risk of fire. PSPS is a ***measure of last resort*** after all other fire prevention measures have been implemented. The drivers leading to the decision to de-energize BVES circuits are provided in Section 4 as well as those to restore from PSPS.

Table 5-1: PSPS Phases for PSPS Procedures

Phase	Timeframe	Internal Staff Actions	External Communications and Notifications
Preparatory	**Pre-fire season.** Conducted annually well before extreme fire threat conditions are expected; or When lessons learned or other conditions warrant updating plans, training, and/or outreach. Coordinate with the CPUC, CalFire, CalOES, communications providers, representatives of people/communities with access and functional needs, and other public safety partners to plan de-energization simulation exercises throughout the utility service territories in the areas with the highest historical and forecasted risk for de-energization in advance of fire season.	**Planning and Training** Managers review and update plans and procedures. Managers ensure staff are trained on PSPS procedures as applicable. Reach out to media and Community-based organizations to ensure consistent awareness of and availability to third-parties of all messaging and map data, including application programming interfaces, that are used for de-energizations events. Customer Service Department will ensure all equipment and supplies for the CRC are functional and readily available.	**Local Government, Agencies, and Partner Organizations:** Provide copy of plan and solicit comments. Incorporate comments as deemed appropriate. Conduct meetings to discuss procedures. Update primary and secondary contacts for PSPS communications. Advisory Board: May consist of public safety partners, communications and water service providers, local and tribal government officials, business groups, non-profits, representatives of people/communities with access and functional needs and vulnerable communities, and academic organizations. **Customer Outreach and Education:** Post PSPS information on BVES's Website and social media. Include PSPS information in periodic customer newsletter. Conduct public workshops. Provide PSPS notifications via email, telephone calls, Interactive Voice Response (IVR) proactive calling system, and two-way text messaging.
Warning	**4-7 Days Ahead** (Forecasts indicate extreme fire threat weather and conditions may occur)	**Operations & Planning:** Evaluate possible impacted area(s) and ensure resources ready to support PSPS. Contact SCE Staff and maintain status of SCE supply lines. Review operational and maintenance status of sub-transmission system. Review operational and maintenance status of Bear Valley Power Plant (BVPP).	**None**

		Review operational and maintenance status of Radford Line. Consider conducting patrol of Radford Line. Review National Weather Service (NWS) forecasts, National Fire Danger Rating System (NFDRS) 7-day forecast, and weather and threat assessments from contracted meteorology consultant. Consider having meteorology consultant provide more frequent forecasts. Alert customer service to possibility of PSPS. **Customer Service:** Review and edit as applicable templates for PSPS events and the anticipated impacts on BVES Customers. Staff drafts notices to Public Affairs consultant for review, significant changes to templates are made. Create warning notifications to customers via email, telephone calls, IVR proactive calling system, and two-way text messaging.	
Warning	**4 Days Ahead** (Continuing and consistent forecasts of extreme fire threat weather and conditions)	**Operations & Planning:** Closely monitor fire weather alerts from various sources with the goal of refining the forecast (NWS, NFDRS, and meteorology consultant weather and threat assessments). Contact SCE Staff and maintain status of SCE supply lines. If any SCE lines are under "PSPS Consideration," take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Consideration. Ensure sub-transmission system is in most reliable condition. Defer and/or secure from planned maintenance. Ensure BVPP ready to operate. Defer and/or secure from planned maintenance.	**Local Government, Agencies, and Partner Organizations:** Email **"4 Day Alert"** to local government, agencies, and partner organizations primary and secondary points of contact. Alert the emergency management community, first responders and local government first.

		Alert Energy Resource Department of possible extended BVPP operations. Consider energizing Radford Line, if deemed necessary for reliability. Closely coordinate with SCE Staff regarding the PSPS status of SCE supply lines (Doble, Cushenberry, and Bear Valley/Radford). Ensure BVES installed weather stations fully operational. Ensure circuit load monitoring equipment fully operational. Place BVES staff incident responders on alert. **Customer Service:** Finalize **"4 Day Alert"** email regarding continuing and consistent forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Also, provide anticipated impacts on BVES Customers and direction of event. Obtain President's approval to release. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	
Warning	**2-3 Days Ahead** (Extreme fire threat weather and conditions forecasted with increasing confidence)	**Operations & Planning:** Continue to closely monitor fire weather alerts from various sources with the goal of refining the forecast (NWS, NFDRS, and meteorology consultant weather and threat assessments). Prepare staff rotation plans to support continuous field crew operations, BVPP operations, dispatch, and customer service.	**Local Government, Agencies, and Partner Organizations:** Email **"2-3 Day Notice"** to local government, agencies, and partner organizations primary and secondary points of contact. Coordinate with the emergency management community, first responders and local government first.

		Evaluate need for additional resources from mutual aid agreements (CUEA and MMAA) and contracted services. Alert additional resources points of contact. Set up processes to frequently monitor BVES installed weather stations. Review pre-approved field Switching Orders against current system line-up and make changes as applicable with Field Operations Supervisor's approval. Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. Closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. **Customer Service:** Finalize **"2-3-Day Notice"** regarding forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts on BVES Customers and direction of event. Obtain President's approval to release. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	Encourage widest dissemination of this information. **Customer Outreach:** Post **"2-3 Day Notice"** on BVES website and social media. Issue **"2-3 Day Notice"** press release for local media. Send out **"2-3 Day Notice"** via IVR. Send out "2-3 Day Notice" via Text Send out "2-3 day Notice" via Email
Warning	**1-2 Days Ahead** (Extreme fire threat weather and conditions	**Operations & Planning:** Continue to closely monitor fire weather alerts from various sources with the goal of refining the	**Local Government, Agencies, and Partner Organizations:**

	forecasted with high degree of confidence)	forecast (NWS, NFDRS, and meteorology consultant weather and threat assessments). If needed, request additional resources from mutual aid agreements (CUEA and MMAA) and contracted services). Monitor BVES installed weather stations on a frequent basis. Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. Set up CRC and conduct a mock SOE scenario to include testing of all equipment and needed supplies. Purchase non-perishable food items to provide to our customers including bottled water. Continue to closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. When directed by the Utility Manager: Staff incident responders called in. Incident dispatch established. Field Crews dispatched to monitor various actual field conditions for extreme fire weather and other dangerous conditions throughout the service area and “at risk” areas. Implement BVES ERP including staffing the EOC as applicable. **Customer Service:** Finalize **“1-2 Day Notice”** regarding imminent extreme fire threat weather and conditions, which may result in BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts	Email **“1-2 Day Notice”** to local government, agencies, and partner organizations primary and secondary points of contact. Coordinate with the emergency management community, first responders and local government first. Encourage widest dissemination of this information. **Customer Outreach:** Post **“1-2 Day Notice”** on BVES website and social media. Issue **“1-2 Day Notice”** press release for local media. Send out **“1-2 Day Notice”** via IVR. Send out “1-2 Day Notice” via Text Activate “1-2 day Notice” via Email

		on BVES Customers and duration of event. Obtain President's approval to release. Update list of medical baseline customers that may lose power as result of PSPS. Update list of AFN customers that may lose power as result of PSPS. BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging	
Warning	**1-4 Hours Ahead When De-Energization Imminent.** (Extreme fire threat weather and conditions validated by field resources)	**Operations & Planning:** Closely coordinate with SCE regarding SCE directed PSPS that affect SCE lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. Field Operations staff frequently monitor BVES installed weather stations. Field Crews patrol throughout service area and the "at risk" areas to monitor various actual field conditions for extreme fire weather and other dangerous conditions. Field Crews monitor local wind gusts in "at-risk" areas. **Customer Service:** Finalize "**De-energization Imminent Notice"** regarding extreme fire threat weather and conditions validated by field resources and actual PSPS de-energization(s) directed by BVES and/or SCE and includes areas de-energized, number of customers without power, and best estimated time	**Local Government, Agencies, and Partner Organizations:** Email **"De-energization Imminent Notice"** to local government, agencies, and partner organizations. Coordinate with the emergency management community, first responders, and local government in managing outages due to PSPS. Provide list of customers that may be without power and listed as medical baseline customers to Sheriff Department and Fire Department. Encourage widest dissemination of this information. **Customer Outreach:** Post "**De-energization Imminent Notice"** on BVES website and social media. Issue "**De-energization Imminent Notice"** press releases for local media. Send out "**De-energization Imminent Notice"** via IVR. Send out "**De-energization Imminent Notice** Day Notice" via Text

		to restore (ETR). Obtain President's approval to release. Refine lists of medical baseline customers without power. Update list of AFN customers that may lose power as result of PSPS BVES will issue a press release to local media (newspaper and radio) and will post notification on website. Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two way text messaging.	Send out "**De-energization Imminent Notice**" via Email
Implementation	**During de-energization event.** (Extreme fire threat weather and conditions validated by field resources)	**Operations & Planning:** Closely coordinate with SCE regarding SCE directed PSPS that affect SCE lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. Field Operations staff frequently monitor BVES installed weather stations. Field Crews patrol throughout service area and the "at risk" areas to monitor various actual field conditions for extreme fire weather and other dangerous conditions. Field Crews monitor local wind gusts in "at-risk" areas. Field Crews de-energize circuits in "at risk" areas as wind gusts reach threshold for de-energization as designated by Field Operations Supervisor. Field Crews may de-energize additional power lines they evaluate as posing a public safety hazard and/or as directed by Field Operations Supervisor. Prepare GO-166 major outage and ESRB-8 notifications as applicable. **Customer Service:**	**Local Government, Agencies, and Partner Organizations:** Email **"De-energization Notice"** to local government, agencies, and partner organizations. Coordinate with the emergency management community, first responders, and local government in managing outages due to PSPS. Send **"De-energization Updates"** on the PSPS. Provide list of customers without power and listed as medical baseline and AFN customers to Sheriff Department and Fire Department. Encourage widest dissemination of this information. Notify California Public Utilities Commission (CPUC) and Warning Center at the Office of Emergency Services San Bernardino within one hour of shutting off the power if the outage meets the major outage criteria of GO-166. Notify President Safety Enforcement Division (SED), CPUC within twelve hours of the power being Shutoff per ESRB-8. **Customer Outreach:**

		Finalize "**De-energization Notice**" regarding extreme fire threat weather and conditions validated by field resources and actual PSPS de-energization(s) directed by BVES and/or SCE and includes areas de-energized, number of customers without power, and best estimated time to restore (ETR). Obtain President's approval to release. Finalize **"De-energization Updates"** providing status changes such as when the number of customers without power and/or ETR(s) change significantly. Obtain President's approval to release. Refine lists of medical baseline customers without power.ES will issue a press release to local media (newspaper and radio) and will post notification on website. Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	Post "**De-energization Notice**" and "**De-energization Updates"** (when warranted) on BVES website and social media. Issue "**De-energization Notice**" and "**De-energization Updates"** (when warranted) press releases for local media. Send out "**De-energization Notice**" and "**De-energization Updates"** (when warranted) via IVR. Send out "De-energization Notice" and "**De-energization Updates"** (when warranted) via Text Activate "De-energization Notice" and "**De-energization Updates"** (when warranted) via Email Communicate with emergency services regarding AFN and medical baseline customers.
Restoration	**Re-energization** (Extreme fire conditions subside to safe levels as validated by field conditions)	**Operations & Planning:** Field Crews validate that the extreme fire weather conditions have subsided to safe levels as designated by the Field Operations Supervisor and report these conditions to Dispatch. Field Crews conduct field inspections and patrols of facilities that were de-energized. When field inspections and patrols are completed satisfactorily, power is restored to the affected circuits. As SCE restores supply lines, Field Crews conduct switching operations as directed by Field Operations Supervisor to restore systems normal. **Customer Service:** Finalize **"Intent to Restore"** notice to include ETR(s) and obtain President's approval to release.	**Local Government, Agencies, and Partner Organizations:** Send **"Intent to Restore"** notice to local government, agencies, and partner organizations. Encourage widest dissemination of this information. Coordinate with the emergency management community, first responders, and local government in managing restorations. Send **"Restoration Complete"** notice to local government, agencies, and partner organizations once power is fully restored or an update if restoration is delayed. **Customer Outreach:** Post **"Intent to Restore"** notice on BVES website and social media.

		Finalize **"Restoration Complete"** notice to be issued when power is fully restored and obtain President's approval to release. Breakdown of CRC including removal/storage of all equipment and supplies.	Issue **"Intent to Restore"** press release for local media. Send out **"Intent to Restore"** notice via IVR. Send out **"Intent to Restore"** notice via Text Send out **"Intent to Restore"** notice via Email Post **"Restoration Complete"** notice on BVES website and social media once power is fully restored or an update if restoration is delayed. Issue **"Restoration Complete"** press release for local media once power is fully restored or an update if restoration is delayed. Send out **"Restoration Complete"** notice via IVR once power is fully restored or an update if restoration is delayed. Send out **"Restoration Complete"** notice via Text once power is fully restored or an update if restoration is delayed. Send out **"Restoration Complete"** notice via Email once power is fully restored or an update if restoration is delayed.
Reporting and Lessons Learned	**Post Event**	**Operations & Planning:** Utility Manager conduct lessons learned with applicable staff. Include Customer Service and solicit input from Local Government, Agencies, and Partner Organizations. If applicable, update plan and procedures per the lessons learned. Prepare PSPS Post Event Report required by ESRB-8 and forward to President and Manager Regulatory Affairs for approval.	**CPUC Safety Enforcement Division:** File a report (written) to President of SED no later than 10 business days after the Shutoff event ends per ESRB-8.

SCE Directed PSPS Procedures. Close coordination with SCE is essential to mitigating the impact of any SCE directed PSPS events that would result in a complete and/or partial loss of SCE supply lines. The following preparatory coordination has been established:

Each year, before the fire season, BVES Management Team will engage SCE Management on coordination for potential and actual PSPS events.
BVES Management Team will update contact information with the SCE Key Account Manager for the BVES account.
BVES Field Operations staff will update contact information with the SCE Lugo and Colton Control Stations which have direct operational control over the SCE supply lines to BVES.

When PSPS events are forecasted and/or implemented, the SCE Key Account Manager will coordinate with the BVES Management Team and the SCE Lugo and Colton Control Stations will coordinate directly with the designated BVES Field Operations Team.

Table 5-2, BVES Action for SCE Lines Under PSPS Consideration, provides procedures to implement to best prepare the BVES system for a complete and/or partial loss of SCE supply lines.

Table 5-2: BVES Action for SCE Lines Under PSPS Consideration	
Condition	**BVES Action**
SCE places Doble or Cushenberry Line under PSPS Consideration.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Operations & Planning Manager evaluate energizing Radford Line for improved reliability.
SCE places Bear Valley Line under PSPS Consideration.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If Radford is energized, shift loads to Shay Line.
SCE places Doble **and** Cushenberry Lines under PSPS Consideration.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Energize the Radford Line. Prepare for potentially losing all SCE supply lines from Lucerne. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads.
SCE places Doble or Cushenberry, and Bear Valley Lines under PSPS Consideration	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Prepare for potentially losing all SCE supply lines from Lucerne. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads.
SCE places Doble, Cushenberry, and Bear Valley Lines under PSPS Consideration	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Prepare for potentially losing all SCE supply lines into BVES service area. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads.

Table 5-3, BVES Action for SCE Lines De-energized Due to PSPS, provides procedures to use in the event of a partial or complete loss of SCE supply lines due to PSPS. These procedures are based on procedures specified in Section 4 to the BVES Emergency Response Plan except that they take into account that BVES will closely coordinate with SCE Staff as follows:

BVES will receive warnings of impending PSPS on the SCE lines about 2 days prior to the event.
BVES will receive updates to the status of the lines under PSPS Consideration.
SCE will notify BVES at least 4 hours prior to de-energizing any SCE supply lines to BVES service area.

These timely notifications will allow BVES to take preparatory action to shed load to within the expected capacity of its remaining sources of power and will allow BVES to avoid a “black start” on the BVPP. Therefore, the procedures of Table 5-3 should be followed during PSPS event. However, if there is a sudden complete or partial loss of

SCE supply lines, the procedures in Section 4 of the BVES Emergency Response Plan are more appropriate and should be followed as directed by the Utility Manager.

Table 5-3: BVES Action for SCE Lines De-energized Due to PSPS

Condition	BVES Action
SCE De-energizes Doble or Cushenberry Line for PSPS.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Energize Radford Line as needed to meet load demand. If the Utility Manager deems it necessary, energize the Radford Line as needed for reliability. 3. Startup of the BVPP as needed to meet load demand. 4. No reduction on load necessary, since the Doble and Cushenberry are capable of carrying the other’s load. 5. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Bear Valley Line for PSPS.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. If Radford is energized, shift loads to Shay Line prior to de-energizing for PSPS. Generally, this should be done about 4 hours prior to the SCE de-energizing the line. 3. If needed, start up the BVPP to meet load demand. 4. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. 5. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Doble or Cushenberry **and** Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Since the Doble and Cushenberry are capable of carrying the other’s load, follow the procedure for “SCE De-energizes Bear Valley Line for PSPS” above. Prepare for potentially losing all SCE supply lines into BVES service area. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Doble and Cushenberry Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If not already done, energize the Radford Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor’s direction, shift as much of the load to the BVPP and Radford Line as follows: Open the Shay and Baldwin ARs. “Express” the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations’ switching order.

Table 5-3: BVES Action for SCE Lines De-energized Due to PSPS	
Condition	**BVES Action**
	Start up the BVPP, place enginators on-line and increase load to within the combined capacity of the BVPP and Radford Line. Implement BVES Emergency Response Plan for sustained loss of SCE supplies from Lucerne including “rolling blackout” procedures. Prepare for sustained BVPP operations and rolling blackouts. Frequently monitor distribution circuit loads.
SCE de-energizes Doble, Cushenberry, and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. If the Radford Line is energized, shift loads to the Shay Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor’s direction, perform the following: Start up all of the BVPP enginators. Reduce system load to within the capacity of the BVPP by isolating distribution circuits as directed by the Field Operations Supervisor. Once system load is matched with the BVPP capacity, open the Shay and Baldwin ARs. Implement BVES Emergency Response Plan for sustained loss of all SCE supply lines including “rolling blackout” procedures.

PSPS Public Outreach and Communications

Importance of Public Outreach. Due to the significant impact that a PSPS event may have on the community and customers, it is essential that early and accurate communications be conducted throughout the PSPS event coincides with local government, agencies, partner organizations (includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and functional needs), and customers. Effective communications are key to allow stakeholders to take preparatory actions that will mitigate the impact of a PSPS event on them.

ERP Communications Procedures. During the time period leading up to the PSPS event, during a PSPS event, and during the restoration period from a PSPS event, the Emergency Response Communications Plan (Section 5) of the Emergency Response Plan (ERP) shall be implemented as applicable in conjunction with this plan.

PSPS Planned Communications. Table 6-1, BVES PSPS Communications Template Listing, are to be prepared by the Customer Program Specialist and be preapproved through the President well ahead of expected PSPS events such that BVES staff may quickly initiate effective communications with stakeholders during a PSPS event. The templates are designed to provide a standard “fill in the blank” notice that may be amended depending on the specific situation as applicable. Templates shall initially be reviewed and edited as applicable by BVES’s public relations contractor. Additionally, the templates shall be reviewed annually and/or when lessons learned indicate changes to the templates are appropriate.

Table 6-1: BVES PSPS Communications Template Listing

Template	Content	Media	Recipients
4-Day Alert	Provides notice of continuing and consistent forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts on BVES Customers and direction of event.	Email	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs), and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing

Template	Content	Media	Recipients
2-3 Day Notice	Provides notice of forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. Provides anticipated impacts on BVES Customers and duration of event.	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
1-2 Day Notice	Provides notice regarding imminent extreme fire threat weather and conditions, which may result in BVES directed PSPS and/or SCE directed PSPS. Also, provides anticipated impacts on BVES Customers and duration of event.	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing

Template	Content	Media	Recipients
De-energization Imminent Notice	Provides notice that BVES directed PSPS and/or SCE directed PSPS is imminent (within 1-4 hours) based on validated extreme fire threat weather and conditions. Also, provides anticipated impacts on BVES Customers and duration of event.	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
De-energization Notice	Provides notice of extreme fire threat weather and conditions validated by field resources and actual PSPS de-energization(s) directed by BVES and/or SCE and includes areas de-energized, number of customers without power, and best estimated time to restore (ETR).	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing			
Template	**Content**	**Media**	**Recipients**
De-energization Updates	During de-energization event, provides notice of changes such as when the number of customers without power and/or ETR(s) changes significantly.	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
Intent to Restore	Provides notice that extreme fire threat weather and conditions have subsided, BVES crews are performing post-PSPS restoration inspections, and ETR(s).	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing			
Template	**Content**	**Media**	**Recipients**
Restoration Complete	Provides notice that power is fully restored.	Email BVES Website Social Media Press Release IVR Message Text Message	Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Critical Facilities and Infrastructure. The term ‘critical facilities’ and ‘critical infrastructure’ refers to facilities and infrastructure that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during PSPS events. The following provides guidance on what constitutes critical facilities and infrastructure:

Emergency Services Sector

Police Stations
Fire Stations
Emergency Operations Centers

Government Facilities Sector

- Schools
- Jails and prisons

Healthcare and Public Health Sector

Public Health Departments
Medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities

Energy Sector: Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly-owned utilities.

Water and Wastewater Systems Sector: Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater.

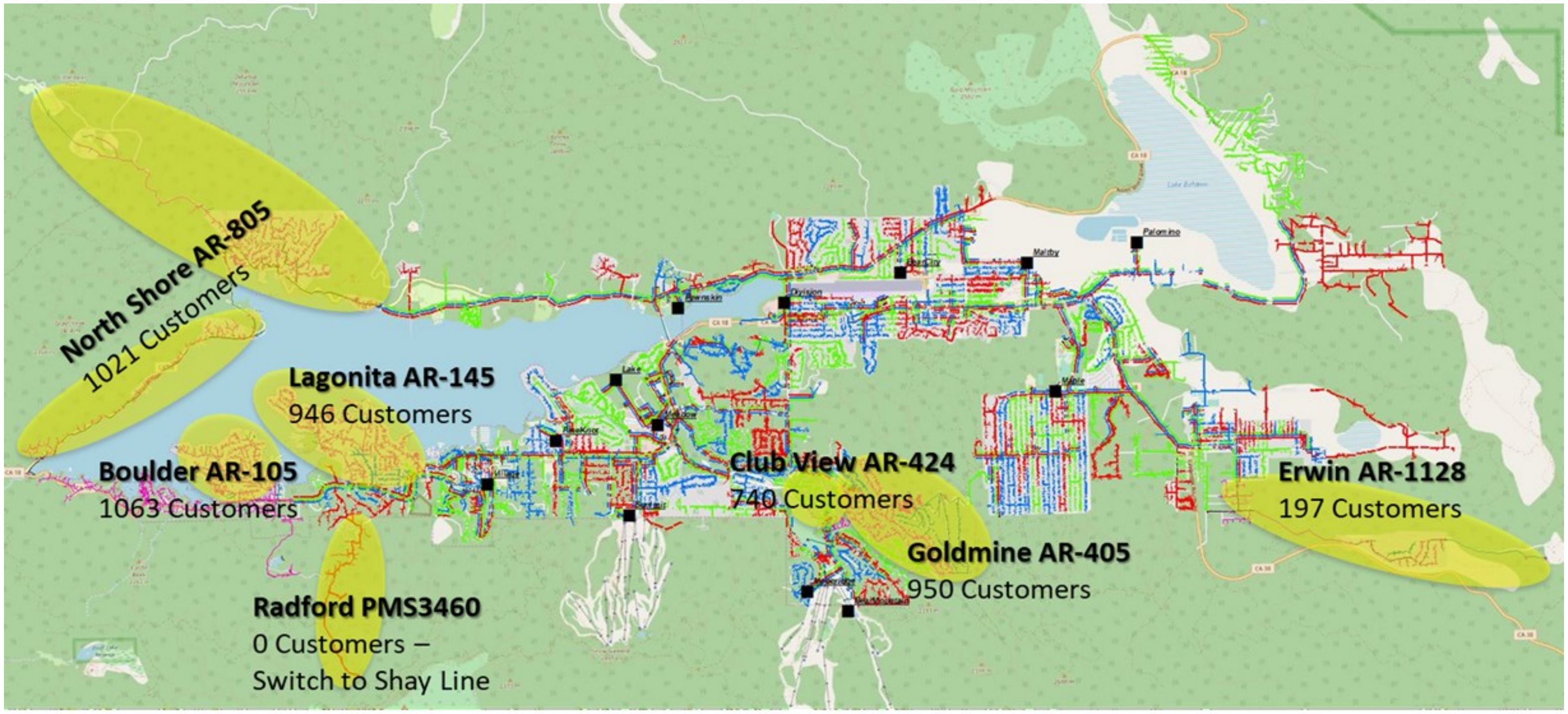
Communications Sector: Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites.

Chemical Sector: Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals.

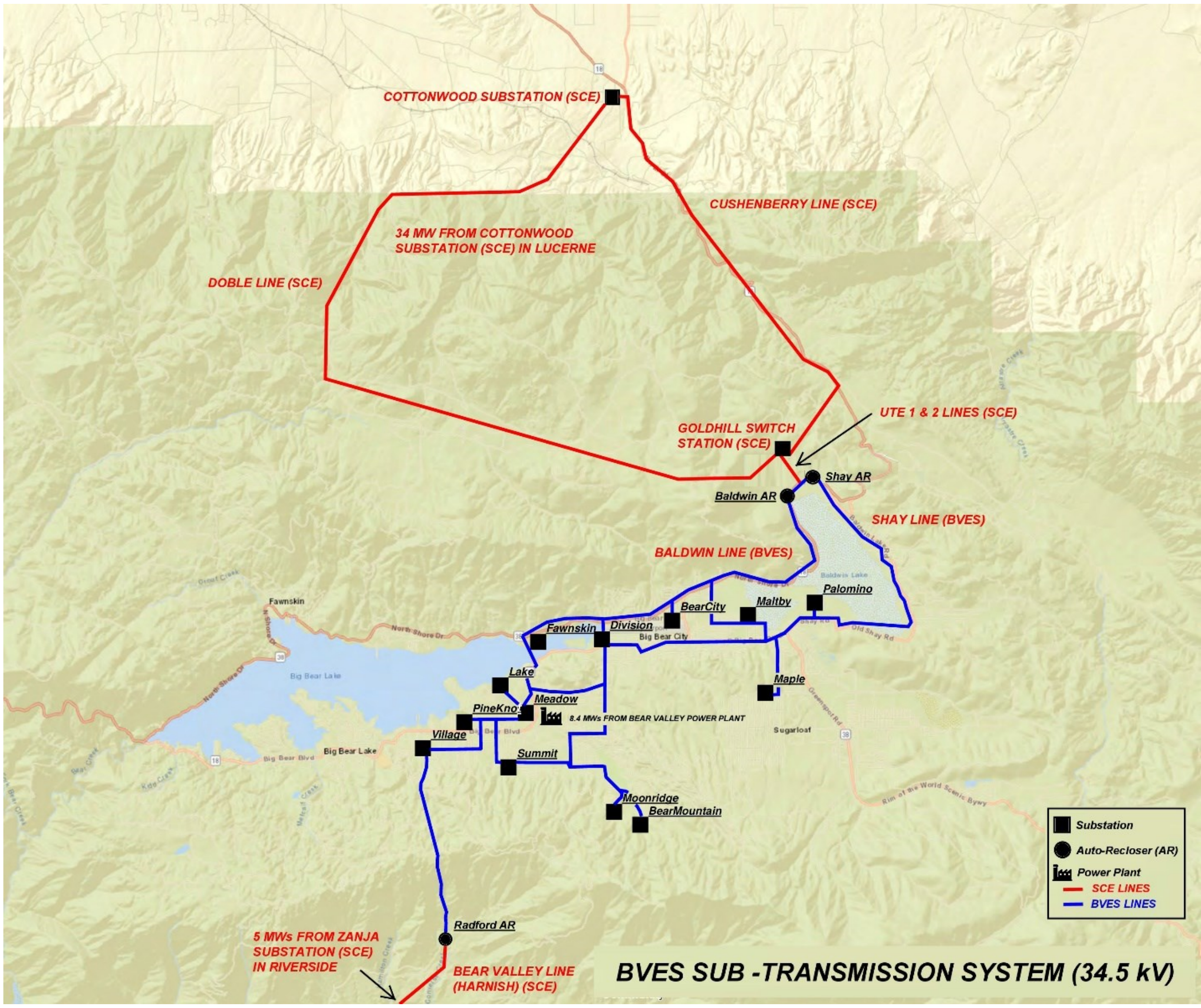
Key Partners. The follow provides the list of pertinent Local Government, Agencies, and Partner Organizations to BVES PSPS notifications. This list overlaps with the list of what is considered critical facilities and infrastructure:

Local officials (City of Big Bear Lake) and San Bernardino County
State officials (normally CPUC Energy Division and Safety Enforcement Division)
San Bernardino County Office of Emergency Services (County OES)
Big Bear Fire Department
California Department of Forestry and Fire Protection (CAL FIRE)
U.S. Forest Service
San Bernardino County Sheriff’s Department Big Bear Lake Patrol Station
California Highway Patrol (CHP) Arrowhead Area
California Department of Transportation (Caltrans)
Big Bear Area Regional Wastewater Agency (BBARWA)
Big Bear City Community Services District (CSD)
Big Bear Lake Water Department (DWP)
Big Bear Municipal Water District (MWD)
Southwest Gas Corporation
Bear Valley Community Hospital
Bear Valley Unified School District
Big Bear Chamber of Commerce
Big Bear Airport District
Big Bear Mountain Resorts
Spectrum Communications
Various cell tower providers

Appendix A: BVES "High Risk Areas" for PSPS Consideration



Appendix B: BVES Supply Lines, Sources of Power and Sub-Transmission System



Appendix C: BVES Community Resource Center Protocols

During a PSPS event, Bear Valley Electric Service, Inc. will set up a Community Resource Center (CRC) at its Main Facility at 42020 Garstin Dr., Big Bear Lake, CA 92315 adjacent to the Warehouse. The Customer Service and Operations Support Supervisor shall be responsible for ensuring these protocols are properly implemented when the CRC is activated.

The CRC shall be operable from 8:00 a.m. to 10:00 p.m. during an active PSPS event. Actual hours of operation will be coordinated and determined by the local government in cases in which early closure of a facility is required due to inability to access a facility until 10:00 p.m.

They will initially be set up in the Warehouse so that quick access and set up may occur.

The setup of the CRC shall be ADA (Americans with Disabilities Act) accessible to meet the needs of people/communities with access and functional needs and medical baseline customers.

At all times the CRC shall comply with social distancing or other public health protocols that are in place.

The following supplies and equipment are stored in the CRC Storage Container to support CRC operations:

Tents (2)
Water
Snacks (such as crackers, granola bars, etc.)
Chairs
Heaters
Extension cords
Disposable masks (as necessary)
Gloves (as necessary)
Hand sanitizer (as necessary)
Flash lights
Small first aid kits
Blankets
Surge Protectors
Gas tank
Generators
Wireless internet access point

The CRC will operate as follows:

The Customer Service and Operations Support Supervisor and Customer Program Specialist will be in charge of the CRC.

The CRC will be set up and operated by:

Field personnel/warehouse person will set up and assist as needed
Customer Service and Operations Support Supervisor
Customer Program Specialist

Security and Access will be conducted by the Customer Service Representatives and Operations Support Specialists.

Customer Service Representatives will staff an Information Booth to provide customers the latest information regarding PSPS and services available to them.

Medical Equipment Access (Generators/power supplies) will be provided for Customers who are on medical devices such as oxygen, etc.

Access to Wi-Fi and back-up cell phones (as necessary) will be provided to Customers.

Until portable restroom facilities are available, customers will have access to the Main Office restroom facilities.

APPENDIX C. BVES EMERGENCY RESPONSE PLAN

Bear Valley Electric Service, Inc.

Emergency & Disaster Response Plan

March 31, 2022

Approved by: Paul Marconi Digitally signed by Paul Marconi
Date: 2022.03.30 13:29:45
-07'00'

Paul Marconi, President, Treasurer, & Secretary

Annual Emergency Response Plan Training and Exercise

Annual Training
Annual Exercise
Exercise Notice
Exercise Evaluation
Emergency Response Outreach Training

Emergency & Disaster Response Communications Plan

Strategy Overview
Establish Multiple and Effective Communication Channels

Outbound Communications
Inbound Communications
Internal Communications

Conduct Pre-Incident Outreach and Education

City and County Outreach
General Public, Customer and Stakeholder Outreach and Education (before an emergency)

Provide Outreach in Prevalent Languages
Provide Emergency Incident Communications

Set Expectations and Develop Trust
Notify and Engage Key Stakeholders
Notify Customers and General Public
Media Engagement Procedures

Authorized Media Engagement
Press Release Content
Press Release Protocols

Post Emergency Event Close-out Statement

Reports to the Commission

Customer Support in Emergencies

Support for Low Income Customers
Billing Adjustments
Deposit Waivers
Extended Payment Plans
Suspension of Disconnection and Nonpayment Fees
Repair Processing and Time
Access to Utility Representatives
Access to Outage Reporting and Emergency Communications

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Purpose and Introduction. The Emergency & Disaster Response Plan (EDRP) is provided to all Bear Valley Electric Service, Inc. ("BVES") employees to ensure an efficient, effective and uniform response during an emergency situation. BVES recognizes the importance of an integrated EDRP in order to safely provide for the energy needs of our customers and the requirements of our stakeholders in the event of an emergency.

The EDRP outlines BVES' philosophy and procedures for managing major emergencies that may disrupt electric service to our customers or threaten the health and safety of the people in the communities we serve. The EDRP further establishes the structure, processes and protocols for the BVES's emergency response and identifies departments and individuals that are directly responsible for that response and critical support services. In addition, it provides a management structure for coordination and deployment of the essential resources necessary for the response.

The EDRP is designed to provide a framework for managing and responding to:

Large outages
Numerous smaller outages
Potential for large outages
Potential for numerous smaller outages
Any combination of the above

The EDRP may be invoked as a precautionary measure when there is a strong potential for outages or in response to actual outages. The EDRP is designed to be implemented as needed in conjunction with other procedures, plans, and policies such as:

Public Safety Power Shutdown Plan
Wildfire Mitigation Plan
Field Operations and Engineering Procedures
Customer Service Procedures
Other organizations such as State, County, and City Emergency Disaster Plans

The EDRP complies with the requirements set forth in the Public Utilities Commission of the State of California's General Order No. 166, Standards for Operation, Reliability, and Safety during Emergencies and Disasters.

Plan Goals. When an emergency occurs, BVES' response actions are guided by the following overriding emergency goals (in order of priority):

Safety: Protect the life-safety of our customers, employees and the general public.
Restoration of Power: Restore electric service to customers in a safe and timely manner.
Communications: Keep customers, stakeholders, and staff informed.

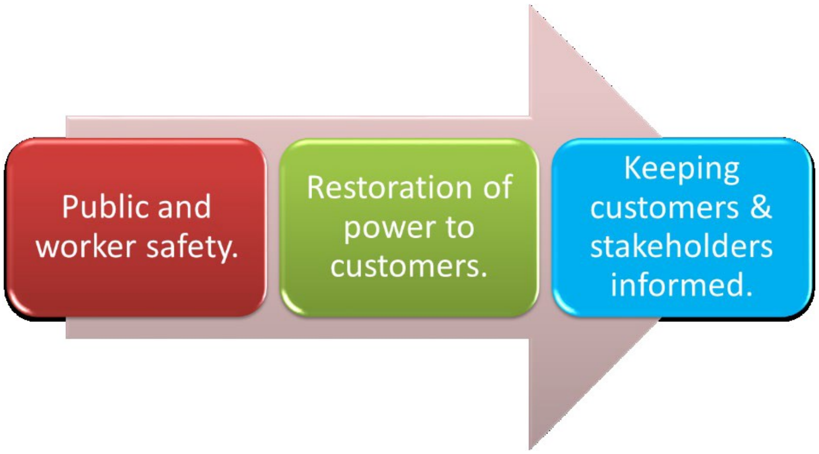

Figure 1-1: EDRP Goals

Plan Vision. BVES strives to meet customer needs through effective risk assessment, mitigation, preparedness, response and communications. Our vision is to achieve excellence in emergency management performance.

Plan Policy. BVES strives to utilize effective emergency management principles that enhance the BVES's ability to provide safe and reliable electric power and its ability to communicate timely and accurate information to customers and stakeholders by:

Conducting effective risk assessments for operating and business functions;
Developing appropriate prevention or risk mitigation strategies;
Implementing comprehensive emergency preparedness programs;
Responding with appropriate resources to address emergencies;
Communicating with customers and other stakeholders with timely and accurate information;
Recovering from events safely and expeditiously; and
Improving continuously.

Since major outage events and emergencies are rarely similar in all respects, the EDRP is constructed in such a way to provide BVES management with a trained and operationally ready workforce and a response operations process that may be employed as required to deal with the unique aspects of each major outage and emergency event.

The effectiveness of the EDRP is based on BVES' commitment to prepare for, to implement, and to review procedures after each implementation. An after action review process shall facilitate continuous improvement in the BVES's response and restoration processes.

Execution of the appropriate response to affect rapid and safe recovery is dependent upon the scalability of this plan. For example, storm intensities and the number of customers affected vary and, therefore, the level of recovery resources committed to each event is adjusted as appropriate even though the operational concepts remain consistent.

Plan Responsibility. It is the responsibility of all Managers and Supervisors to ensure the EDRP is reviewed by all staff and is updated when appropriate. Specific responsibilities are provided throughout the EDRP.

General Overview. BVES customers receive electric service through an overhead and underground distribution system. Extreme weather events such as heavy rain, hail, snow, ice, lightning, high winds, and/or extreme dry heat may adversely impact the integrity of the distribution system, resulting in occasional interruptions of electric service. The distribution system is also susceptible to damages as a result of major disasters, such as earthquakes, flooding, wildfires, and mud and rock slides. Furthermore, in the interest of public safety, BVES may deem it necessary to proactively de-energize large portions of the distribution system to protect the public; for example, BVES may de-energize circuits or portions of circuits during extreme fire threat weather conditions. BVES normally imports power to its service area via Southern California Edison's (SCE) transmission lines. Therefore, the BVES service area may be susceptible to outages caused by events outside of its services area. All of the above may result in major power outages of varying extent and length depending on the severity of the event. Since electricity is a critical element in our daily lives, prompt restoration is a reasonable customer expectation and a BVES goal. In the case of major disasters, rapid and efficient restoration of power; especially to critical infrastructure, is essential to overall community disaster recovery.

The response to customer outages caused by severe weather events, other disasters or events affecting power delivery to the BVES service area is predicated on recognizing and understanding the magnitude of the event as well as the availability of resources to support the restoration process. This plan has been designed to provide a systematic organized response plan for the purpose of promoting a safe and efficient recovery from any of those conditions. Since the potential of sustaining damages is highest for storm situations, the plan specifically addresses these situations but it may easily be adapted to major outages caused by other disasters or causes.

It is also recognized that no plan can possibly predict and cover every emergency situation. Therefore, the EDRP provides a structure that is based on a set of reasonable assumptions for the most likely emergencies requiring emergency response; but it also provides the BVES's Incident Commander the authority, flexibility, and discretion to alter the BVES's emergency response to tailor it to the specific emergency situation in order to optimize the utilization of BVES resources and to achieve the emergency response goals in an effective and efficient manner.

A critical component of the EDRP is close coordination with stakeholders that depend on BVES's service and assistance for their response actions and who may, also, be able to assist BVES in its response actions. The coordination must occur in developing the plan, training on the plan, executing the plan, and in plan refinements. Some of BVES's major stakeholders include:

Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
State officials (California Public Utilities Commission)
San Bernardino County Office of Emergency Services (County OES)

Big Bear Fire Department
California Department of Forestry and Fire Protection (CAL FIRE)
U.S. Forest Service
San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
California Highway Patrol (CHP) Arrowhead Area
California Department of Transportation (Caltrans)
Big Bear Area Regional Wastewater Agency (BBARWA)
Big Bear City Community Services District (CSD)
Big Bear Lake Water Department (DWP)
Big Bear Municipal Water District (MWD)
Southwest Gas Corporation
Bear Valley Community Hospital
Bear Valley Unified School District
Big Bear Chamber of Commerce
Big Bear Airport District
Big Bear Mountain Resort
Various media and communications companies

Accurate, effective and timely communications with key stakeholders is critical in emergency response and, therefore, it is essential that business relationships be developed before emergency response is necessary. Understanding stakeholders' key staff, contact information, roles and responsibilities, and capabilities are extremely useful in achieving successful emergency response.

Definitions.

Accessible: A condition which permits safe and legal access.

Access and Functional Needs Populations: Refers to those populations with access and functional needs as set forth in Government Code § 8593.3. Access and functional needs population consists of individuals, including but not limited to, individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.

Appropriate Regulatory Authority: The agency or governmental body responsible for regulation or governance of the utility.

Critical Customers: Customers requiring electric service for life sustaining equipment.

Emergency or Disaster: An event which is the proximate cause of a major outage, including but not limited to storms, lightning strikes, fires, floods, hurricanes, volcanic activity, landslides, earthquakes, windstorms, tidal waves, terrorist attacks, riots, civil disobedience, wars, chemical spills, explosions, and airplane or train wrecks.

Essential Customers: Customers representing critical infrastructure and Public Safety Partners.

Major Outage: Consistent with Public Utilities Code Section 364, a major outage occurs when 10 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. For utilities with less than 150,000 customers within California, a major outage occurs when 50 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service.

Measured Event: A Measured Event is a Major Outage (as defined herein), resulting from non-earthquake, weather-related causes, affecting between 10% (simultaneous) and 40% (cumulative) of a utility's electric customer base. A Measured Event is deemed to begin at 12:00 a.m. on the day when more than one percent (simultaneous) of the utility's electric customers experience sustained interruptions. A Measured Event is deemed to end when fewer than one percent (simultaneous) of the utility's customers experience sustained interruptions in two consecutive 24-hour periods (12:00 a.m. to 11:59 p.m.); and the end of the Measured Event in 11:59 p.m. of that 48-hour period.

Public Safety Partners: First/emergency responders at the local, state and federal level, water, wastewater and communication service providers, community choice aggregators (CCAs), affected publicly-owned utilities (POUs)/ electrical cooperatives, tribal governments, the Commission, CalOES and CAL FIRE.

Safety Standby: Interim activities undertaken to mitigate immediate public safety hazards

Serviceable Customer: A customer prepared and properly equipped to receive service where both the customer's electrical service facilities and those facilities of the utility necessary to serve the customer can be legally and physically accessed in a safe manner.

Sustained Outage: An electric service interruption (0 voltage) lasting greater than 5 minutes.

Emergency Response Organization. The EDRP requires that in responding to emergencies, the BVES's staff shall be organized largely based on the Standardized Emergency Management System (SEMS) as interpreted by the BVES. The SEMS structure utilized by BVES is a utility compatible Incident Command Structure (ICS) framework designed to manage emergency incidents and events.

Standardized Emergency Management System. SEMS is an emergency preparedness and response system that has been endorsed by the State of California. It is the cornerstone of

California's emergency response system and the fundamental structure for the response phase of emergency management. It unifies all elements of California's emergency management community into a single integrated system and standardizes key elements. Additionally, it provides a common structure for all organizations responding to an emergency situation and a means of systematic planning. The benefits of using the SEMS include:

Use of common terminology among agencies.
Use of parallel organizational functions among agencies.
Provides a standard means of systematic planning.

The basic SEMS organization structure is shown in Figure 2-1, SEMS Organization:

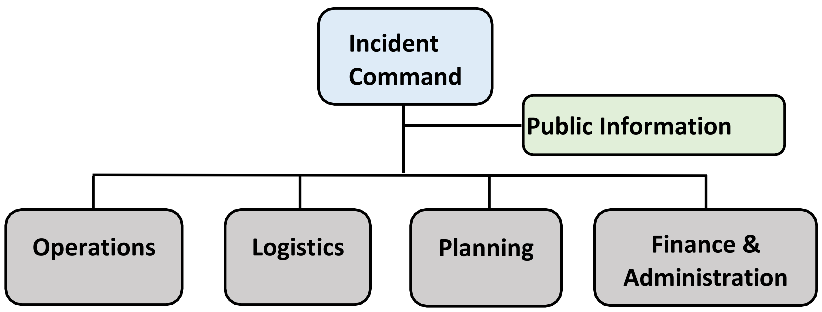

Figure 2-1: SEMS Organization

By organizing the response team along the SEMS structure, the BVES emergency response team is able to coordinate with other government and agencies via their corresponding groups. For example, BVES Operations would coordinate directly with the City of Big Bear Lake Emergency Operations Center or the San Bernardino County OES Operations Groups as applicable. Additionally, when BVES sends a representative to these two centers the representative shall already have a good understanding of the emergency response organization.

BVES Emergency Organization. The organization chart presented below in Figure 2- 2, BVES Emergency Organization, provides the BVES Emergency Organization structure for the full mobilization (Level 1) of BVES' staff in responding to emergencies per this plan. It is the intent that this organizational structure would operate out of an Emergency Operations Center (EOC) established by BVES and be sustainable for long-term emergency response activities.

BVES Emergency Organization

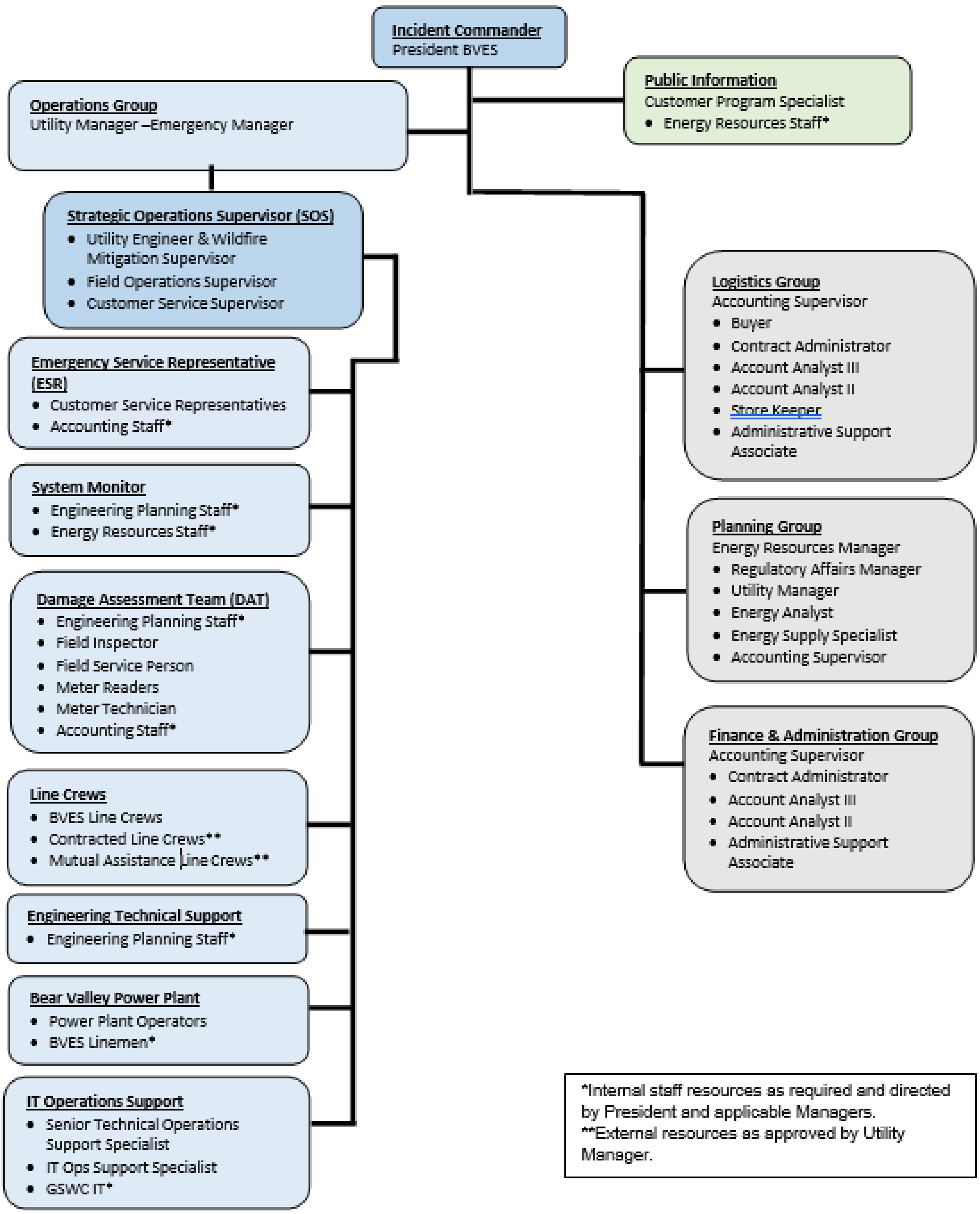

Figure 2-2: BVES Emergency Organization

The specific description of roles and responsibilities for the positions in the BVES Emergency Organization are provided in Section 2.4.

BVES Emergency Operations Center (EOC). An EOC shall be designated for BVES staff use in the event of an emergency. The EOC is the central command and control facility responsible for carrying out the principles of emergency preparedness and emergency response functions described in the EDRP, ensuring public and worker safety, continuity of operations, and timely communications with customers and stakeholders.

An EOC is primarily responsible for strategic direction and operational decisions. Due to the relatively small size of BVES, the Strategic Operations Supervisor (SOS) under the direction of the Operations Group at the EOC shall provide tactical emergency response direction and directly control field assets. The activities under the SOS' management at the EOC shall include all dispatch functions to include customer communications and field operations. For the purpose of the EDRP, when "dispatch" functions are referred to the EOC they are intended for the SOS and supporting team at the EOC.

The common functions of the EOC is to collect, gather and analyze data; make decisions that protect public and worker safety and property; safely maintain and/or restore continuity of operations, within the scope of applicable regulations and laws; and disseminate those decisions to all concerned customers and stakeholders in a timely manner.

The EOC is where the Incident Command, Operations, Planning, Logistics, Financial & Administration, and Public Information groups are located and come together. It serves as the central point for:

Information gathering and dissemination.

Directing emergency and restoration operations at both the strategic and tactical level.
Coordinating with other external agencies and stakeholders.
Developing and issuing customer and stakeholder communications.
Evaluating available resources and requesting or relinquishing resources as appropriate.

The EOC shall meet the following requirements:

Be available for immediate occupancy.
Have access to backup electrical power.
Contain access to multiple communication systems such as telephones, mobile phones, VHF radio, internet service, Interactive Voice Response (IVR), etc.
Be equipped with emergency supplies, system maps and operating information.
Be capable of sustaining long-term emergency response.

The primary EOC for BVES shall be located at BVES' Main Office at 42020 Garstin Dr., Big Bear Lake, CA 92315 in the "Main Conference Room."

The Utility Manager is responsible for ensuring the primary EOC is ready for immediate occupancy. Appendix A, EOC Preparedness and Setup Checklist, provides a list of equipment, capabilities, materials and supplies that should be available to the primary EOC. Some items need not be located in the EOC, but should be in close proximity and readily accessible to EOC staff. The Senior Technical Operations Support Specialist shall maintain

Appendix A up to date as configuration and technology changes are implemented and provide the Administrative Support Associate the latest version of the checklist. The checklist will also be maintained in the EOC.

If the primary EOC will not be ready for immediate occupancy, the Utility Manager shall establish an alternate EOC that is ready for immediate occupancy and shall notify BVES staff. Table 2-1 below provides a list of possible alternate EOCs to be considered.

Table 2-1: Possible Alternate Emergency Operation Centers

Location	To Be Considered
Operations & Planning spaces at the BVES Main Office	Primary EOC not available. Also consider this site, when scope of emergency response activation is reduced (such as Level 2 activation) and all or most activity is carried out by Field Operations.
BVES's General Office in San Dimas, California	When evacuation of the BVES service area is ordered.
State or County's Incident Commander's base camp	When the BVES Main Office is not accessible.
Other suitable area designated by the Utility Manager	When primary EOC is not accessible or available and the above options are not the optimal location.

In selecting an alternate EOC location, the Utility Manager shall at a minimum consider the following factors:

Safety of BVES emergency response staff
Location of hazards and potential movement of hazards
Location of the emergency
Communications capability and ability to coordinate efficiently with stakeholders
Location and accessibility to BVES resources (staff, equipment, material, etc.)

Roles and Responsibilities. This section provides the general intended roles and responsibilities of the BVES Emergency Organization shown in Figure 2-2. It should be noted that the Incident Commander and Group Leaders have the authority to modify roles and responsibilities of those under their responsibility to optimally respond to the specific emergency event. When modifications are made, these should be included during the after action report for the event so that possible changes to the EDRP may be considered. BVES has a small staff, therefore, in the interest of sustainability, efficiency and effectiveness, some staff are "dual hatted" and may be assigned multiple roles and responsibilities.

Incident Commander

President, BVES is the primary BVES staff assigned. Alternates that may be assigned include:

Utility Manager, Energy Resources Manager, Regulatory Affairs Manager, or other BVES officials as directed by the Chief Executive Officer (CEO).

Incident Commander reports directly to the CEO.

Overall responsible for organizing and directing the EDRP by providing strategic direction for the emergency response. Activities associated with the Incident Commander are mostly strategic in nature and include, but are not limited to:

Direct EOC activation. Based on the emergency level and the particular situation surrounding the emergency, may direct partial activation of the EOC.
Authorize de-activation of the EOC (or any partial de-activation).
Authorize use of alternate EOC location when appropriate.

- Provide timely and accurate updates to Senior BVES management (CEO, CFO, VP Regulatory Affairs, etc.) of emergency response.
- Approve and/or conduct high-level communications with federal, state, county, and/or city officials as well as other utilities and non-governmental organization (NGOs).
- Approve and/or conduct external communications with media and the public.
- Approve regulatory reports for outages, incidents and accidents (GO-95, GO-128 & GO-166). Work closely with Regulatory Affairs at the General Office (GO).
- Approve situation reports that may be requested by external organizations such as California Utility Emergency Association (CUEA), State of California Office of Emergency Services (OES), San Bernardino County OES, City of Big Bear Lake, California Public Utilities Commission (Safety Enforcement Division and Energy Division), local Incident Commander, etc.
- Ensure Operations, Planning, Logistics, and Finance & Administration Groups (SEMS) are properly resourced to respond to emergency.
- Lead periodic update meetings with the BVES SEMS Group Leaders.
- Approve requests for mutual aid.
- Approve use of emergency contracting and procurement provisions.

Public Information Group.

Customer Program Specialist is the primary BVES staff assigned to this group. Alternates who may be assigned include: Energy Supply Specialist, Customer Service Supervisor, or others as designated by the Incident Commander. Generally, the Customer Program Specialist and Energy Supply Specialist (or other staff assigned) shall alternate shifts.

Public Information reports directly to the Incident Commander on all public information issues and coordinates directly with the leaders of the Operations, Planning, Logistics and Finance & Administration Groups to stay informed on the latest status of the emergency response. Attends BVES SEMS leadership meetings.

Public Information facilitates communication with all stakeholder groups, including the news media and provides a variety of public information services during an electric system emergency.

Activities associated with Public Information include, but are not limited to:

Develop public engagement strategy and directs all aspects of public messaging.

- Keep customers, stakeholders, BVES management and employees informed on the status of the emergency response including extent of outages, cause of outages, damage and casualty assessments, restoration efforts in progress and planned, estimated time to restore service, and updates to the emergency response through widely available communications channels.

Act as the central point of contact for any external public inquiries.

Prepare and distribute public information releases for media, website, social media, interactive voice response and two-way text messages, state and local government, and other BVES stakeholders.

- Prepare and distribute responses to media inquiries.
- Coordinate with the General Office and other stakeholder public information officials.
- Work closely with the Incident Commander, public relations contractor and General Office (Regulatory Affairs) on public engagement.
- Work closely with other SEMS Groups to be informed of latest information.
- Provide line crews, customer service and other staff who operate in the field or interact directly with customers with the latest information to be shared with public.
- Coordinate participation in joint press conferences with other stakeholders as needed or directed.
- Organize press conferences as needed or as directed.
- Assist in preparing the Incident Commander and other BVES staff for press conferences and interviews.
- Follow media and social media for discussion of BVES and develop rapid response to dispel erroneous information.
- Update BVES website, social media, local media, interactive voice response and two-way text messages, and other communications platforms as conditions change.
- Activate advertising campaigns with local media when appropriate.

<u>Operations Group</u>. The Operations Group is overall responsible for all of the emergency response actions in the field necessary to safely restore service to customers. As such, this group is made up of customer service, line crews, field operations, engineering and planning, and power generation staff and contractors. The Emergency Manager leads this group.

<u>Emergency Manager</u>. Utility Manager is the primary BVES staff assigned. Alternates who may be assigned include: Energy Resource Manager, Utility Engineer & Wildfire Mitigation Supervisor and Field Operations Supervisor. The Emergency Manager reports directly to the Incident Commander. Activities associated with the Emergency Manager are partly strategic and partly tactical in nature and include, but are not limited to:

Ensure public, employee and contractor safety is top priority in all restoration activities.

Authorize deviations to the EDRP as necessary to safely, efficiently and effectively execute restoration activities.

Attend BVES SEMS leadership meetings.
Issue the work schedule and shift rotations for all staff and contractors assigned to the Operations Group.

- Direct the number of Emergency Service Representatives, System Monitors, Damage Assessment Teams, and Line Crews to be assigned per shift.
- Ensure staff and contractors are adequately rotated to allow for rest and safe operations.
- Authorize overtime labor expense as needed.

Direct all restoration and emergency response activities in the field.
Keep Incident Commander and Public Information informed of progress.
Drive to obtain and communicate “estimated time of restoration” (ETR) for outages and update this information as the situation progresses.
Coordinate with other SEMS Groups.
Constantly evaluate restoration progress and optimize utilization of available resources to safely, efficiently and effectively restore service.

- Identify and request additional resources when needed and stand-down resources when no longer required.
- Coordinate restoration activities with other external entities (City, County, Fire Department, Sheriff, CHP, Forestry Service, CALTRANS, other utilities, contractors, etc.).
- Assign and dispatch a knowledgeable BVES representative to local government and/or agency Incident Command as needed.
- Ensure outages, incidents, and accidents are properly documented.
- Assist in preparing regulatory reports for outages, incidents, and accidents (GO-95, GO-128 & GO-166).
- Prepare external situation reports as requested.
- Ensure cost recovery records and documentation for restoration work are being maintained as requested by the Finance and Administration Group.
- Review weather forecast and other external information to optimize restoration response.
- Prepare mutual aid inquiries and requests.
- Communicate logistics requirements to complete restoration activities.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on logistics issues.
- Perform other operations activities as directed by the Incident Commander.

Strategic Operations Supervisor (SOS). The Field Operations Supervisor, Utility Engineer & Wildfire Mitigation Supervisor, and Customer Service Supervisor are the primary BVES staff assigned. Alternates who may be assigned include: Utility Manager and the Regulatory Compliance Project Engineer. The SOS reports directly to the Emergency Manager. Activities associated with the SOS are mostly tactical in nature and include, but are not limited to:

Ensure public, employee and contractor safety is top priority in all restoration activities.
Maintain the “common operational picture” in the EOC. Utilizes the Outage Management System (OMS), Supervisory Control and Data Acquisition (SCADA), CC&B, GIS applications, and other applications to manage information and data in support of restoration efforts.
Act as the Emergency Manager’s direct representative in the EOC and direct all operations

activities to include all dispatch functions while the EOC is activated. For the purpose of this EDRP, the SOS is equivalent to "Dispatch" and the terms may be used interchangeably.
Function as the central Dispatch during EDRP implementation. Receive, prioritize, dispatch, and resolve all Field Activities (FA's) and Transmission and Distribution (T&D) system problems reported by other means per BVES priorities identified in the EDRP.
Direct all restoration and emergency response activities in the field.

Direct and supervise the Emergency Service Representative(s), System Monitor, Damage Assessment Team(s), Line Crews (BVES, contracted and/or mutual aid), Bear Valley Power Plant Operators, IT Operations Support and Contracted Services (for example, snow removal, vegetation management, etc.) in all aspects of EDRP activities.

Ensure resources are safely, efficiently and effectively deployed per the EDRP priorities and as directed by the Emergency Manager.
Recommend to the Emergency Manager whether to increase, maintain, or decrease restoration resources to safely, efficiently, and effectively execute the restoration activities.
Properly document outages, incidents, and accidents.
Maintain cost recovery records and documentation of work completed as requested by the Finance Group at the General Office.
Review weather forecast and other external information to optimize restoration response.
Develop logistics requirements necessary to complete restoration activities.
Keep Emergency Manager and Public Information informed of progress.
Update Situation Report.
Dispatch the Bear Valley Power Plant (BVPP) as needed. Coordinate any logistics necessary to operate the power plant.
Ensure accurate and detailed status of T&D switches, equipment and facilities are maintained in the EOC and updated as changes occur.
Approve field switching orders and direct all field switching operations.
Mostly operate in the EOC but may go out to the field as needed to personally view issues. When departing the EOC, the SOS should designate a knowledgeable staff member to be in charge of the EOC during his absence. It may be advantageous for the off-going SOS to tour outage sites immediately after shift and provide the SOS a report. Alternatively, it may be advantageous for the on-coming SOS to tour outage sites prior to shift.

Emergency Service Representative (ESR). BVES staff who are assigned to this task are the Customer Service Representatives and the Customer Service Specialist. The number of ESR staff assigned per shift shall be directed by the Emergency Manager. Other staff may be requested to augment the ESR Team or to augment certain functions of the ESR Team (for example, EOC staff may be used to call back customers as needed). Additionally, the ESR function or some portions of the ESR function may be transferred to BVES's contracted call center during non-business hours when call volume is low. ESR staff reports directly to the SOS. Activities associated with the ESR Team include, but are not limited to:

Process incoming customer calls.
Issue FA's as appropriate.
Route FA's to EOC dispatch for action.

Update the Outage Management System as applicable.
Assist EOC Dispatch in organizing and prioritizing incoming FA's as directed by SOS.
During extremely high volume periods, alternative procedures may be employed to route FA's more efficiently as directed by the Emergency Manager. For example, the ESRs may be requested to route a periodic CSV file from CC&B of new FA's to EOC Dispatch instead of individual FA's.

May be assigned to provide first layer of sorting FA's by type (outage, line down, etc.) as directed by the SOS.

Respond to customer inquiries on system status using latest information from EOC.
Provide SOS information on customers with "Life Support" and Access and Functional Needs (AFN) customers affected by outages.
Update IVR and two-way text messages as directed by the SOS.

Update Customer Care and Billing (CC&B) with results of completed FA's from EOC.
Call customers to verify power restoration as directed by SOS.
Normally ESR staff perform assigned duties in the Customer Service area. The Emergency Manager may direct ESR staff to work at another area.

System Monitor. Staff assigned to this position are directed by the Emergency Manager and are generally selected from the following staff: Energy Analyst, Regulatory Compliance Project Engineer, Wildfire Mitigation & Reliability Engineer, Utility Planner, GIS Specialist, Engineering Technician, Engineering Inspector, Substation Technician, Meter Technician, Field Inspector, Senior Account Analyst, Account Analyst, and Administrative Support Associate. Other staff as deemed qualified by the Emergency Manager may also be assigned. Normally, one System Monitor shall be assigned per shift but additional System Monitors may be assigned to certain shifts when activity is expected to be high. The System Monitor reports directly to the SOS. Activities associated with the System Monitor include, but are not limited to:

Assist the SOS in maintaining the "common operational picture" in the EOC. Utilizes the Outage Management System (OMS), SCADA, CC&B, GIS applications, and other applications to manage information and data in support of restoration efforts.
Work closely with Emergency Service Representatives to transfer information.
Update the Situation Report.
Assist in receiving, prioritizing, dispatching, and resolving all FA's and T&D system problems reported by other means per BVES priorities identified in the EDRP.

Take reports from the Line Crews, Damage Assessment Teams and other field assets and communicate this information to appropriate EOC staff.
Document outages, incidents, and accidents.
Maintain cost recovery records and documentation of work completed as requested by the Finance and Administration Group.
Review weather forecast and other external information and provide this information to the SOS and Emergency Manager.
Maintain status of the BVPP as needed.
Assist SOS in maintaining an accurate and detailed status of T&D switches, equipment and

facilities in the EOC.
Assist the SOS in execution of responsibilities as directed.
Perform assigned duties in the EOC.

Damage Assessment Team (DAT). Staff assigned to this team are as directed by the Emergency Manager and are generally selected from the following staff: Field Inspector, Substation Technician, Meter Technician, Field Serviceperson, Meter Readers, Wildfire Mitigation & Reliability Engineer, Utility Planner, GIS Specialist, Engineering Technician, Engineering Inspector, Buyer, Storekeeper, Regulatory Compliance Project Engineer, and Energy Analyst. Other staff as deemed qualified by the Emergency Manager may also be assigned to this team. Normally, each DAT shall consist of two people. At least one DAT shall be assigned to each shift. Additional DATs may be assigned to certain shifts when activity is expected to be high. The DAT reports directly to the SOS. Activities associated with the DAT include, but are not limited to:

Assist the SOS in execution of responsibilities as directed.
Perform field investigations as directed by SOS.
Keep the SOS informed of their position when out in the field.
Provide detailed assessments and documentation including photographs and video of damage to SOS.
Coordinate with and assist Line Crews as directed by SOS.
Normally travel in pairs; especially during storm and other potentially hazardous conditions and at night. When conditions are favorable, the Emergency Manager may permit DAT field inspections to be performed by a single person.
When not in the field, perform duties in the EOC as directed by the SOS.

Line Crews. Staff assigned to this crew are BVES Journeyman Lineman Crews (including Apprentice employees). Other BVES staff that are Journeyman Lineman (for example, Field Inspector) may be assigned as needed and directed by the Emergency Manager to augment BVES Line Crews. Emergency Manager may also assign Contracted Line Crews and Line Crews from other utilities through mutual aid agreements. The Emergency Manager shall direct the specific crew sizes, shift lengths and rotations, and functions (such as construction, service response, wire down and minor damage response, switching operations, patrols, damage assessments, etc.). The Line Crews report directly to the SOS. Activities associated with the Line Crews include, but are not limited to:

Perform field activity work (such as construction, service response, wire down and minor damage response, switching operations, patrols, damage assessments, etc.) as directed by SOS.
Keep SOS informed of work progress and developments in the field.
Keep SOS informed of the status of T&D switches, equipment and facilities.
Provide information (such as labor hours, equipment usage, and material consumption) to allow the collection of accurate cost recovery records and documentation for work completed.
Assist in documenting outage and T&D system damage and restorations efforts.

Consult with SOS on technical issues that may require Engineering & Planning evaluation and input.
Request additional resources as needed.
Operate Bear Valley Power Plant engines as directed.

Engineering Technical Support. The primary assigned are Engineering and Planning staff (Utility Engineer & Wildfire Mitigation Supervisor, Regulatory Compliance Project Engineer, Utility Planner(s), Wildfire Mitigation & Reliability Engineer, GIS Specialist, Engineering Technician, and Engineering Inspector) as designated by the Emergency Manager. This function may be augmented by mutual aid from other utilities and/or qualified contractors as the Emergency Manager deems necessary. Normally, Engineering Technical Support is an "on-call" function as requested by the SOS. Engineering and Planning staff are generally "dual hatted" and perform other EDRP functions as assigned by the Emergency Manager. When there is a need for Engineering Technical Support, the System Monitor and SOS shall prioritize the specific workload for each Engineering and Planning staff (for example, Utility Planner may be pulled from the DAT to perform planning activities such as loading assessments on pole replacements and then return to DAT duties once the engineering work is completed).

BVPP Operators. Primary assigned are the BVPP Operators. BVES Journeyman Lineman may also be assigned as directed by the Emergency Manager. Additionally, the Emergency Manager may contract out for additional BVPP Operators, if needed. The Emergency Manager shall direct BVPP Operators and their shift schedule as necessary to support the anticipated or actual dispatching of the power plant. The BVPP Operators report directly to the SOS. Activities associated with the BVPP Operators include, but are not limited to:

Operate the BVPP as directed by SOS.
Maintain BVPP at the ready when not dispatched.
Ensure backup systems fully operational.
Ensure readiness to perform "Black Start" procedure.
Request additional resources as needed.
Document materials and labor hours expended.

IT Operations Support. Primary assigned is the Senior Technical Operations Support Specialist and the Technical Operations Support Specialist. GSWC IT resources may provide backup support for this function. IT Support shall report directly to the SOS. Activities associated with IT Support include, but are not limited to:

Ensures utmost business continuity by monitoring and maintaining EOC, Operations & Planning, Customer Service, Accounting and Energy Resources communications and IT systems are operating properly.
Provides support to ensure connectivity to critical applications.
Coordinates communications and IT systems issues with GSWC IT.
Resolves local IT and network connectivity issues with field equipment and systems (for example, SCADA).

Coordinates communications and connectivity with other entities as directed.
Assists with other duties as directed by the SOS.

Logistics Group.

The Accounting Supervisor is the primary BVES staff assigned in charge of the Logistics Group. Alternates that may be assigned include the Senior Accounting Analyst, Buyer or others as designated by the Incident Commander.

The Logistic Group shall normally be made up Accounting Supervisor, Senior Account Analyst, Buyer, Storekeeper, Accounting Analyst, Administrative Support Associate, and other staff as designated by the Incident Commander.

Logistics Group reports directly to the Incident Commander on all logistics issues and coordinates directly with the leaders of the Operations, Planning, Logistics and Finance & Administration Groups to provide optimal logistics support to ensure restoration activities are safe, efficient and effective. Activities associated with Logistics Group include, but are not limited to:

Group leader attends BVES SEMS leadership meetings.
Maintain at least one group member at the EOC. EOC presence may be modified to "on call" when logistics work is not significant (for example, during night shift) as approved by the Incident Commander.

- Work closely with Emergency Manager and SOS to forecast contracted services, equipment and material requirements for restoration activities.
- Invoke contracts for response services as requested by the Emergency Manager (for example, emergency line work, snow clearing, tree trimming and clearing, etc.).
- Process emergency contracts and procurement requests as needed to support emergency restoration activities.
- Ensure materials for recovery activities are available, issued to Line Crews as needed, and properly documented when utilized or consumed.
- Ensure vehicle fleet fueled, winterized and ready to support response activities.
- Ensure BVES facilities properly functioning to support EOC and response activities.
- Arrange meals as necessary for staff engaged in response activities.
- Arrange lodging and other mobilization logistics for mutual aid and contracted crews as requested by the Emergency Manager.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on logistics issues.
- Perform other logistics activities as directed by the Incident Commander.
- Develop lists of lessons learned for after action evaluation and improvements to logistics.

Planning Group.

The Energy Resources Manager is the primary BVES staff assigned in charge of the Planning Group. Alternates that may be assigned include the Utility Manager, Regulatory Affairs Manager, or others as designated by the Incident Commander.

The Planning Group shall normally be made up of the Regulatory Affairs Manager, Utility Manager, Customer Care and Operations Support Supervisor, Accounting Supervisor, Energy Supply Specialist, Energy Analyst, and other staff as designated by the Incident Commander.

The Planning Group reports directly to the Incident Commander on all planning issues and coordinates directly with the leaders of the Operations, Logistics and Finance & Administration Groups to provide optimal planning support to ensure restoration activities are safe, efficient and effective. Activities associated with Planning Group include, but are not limited to:

Group leader attends BVES SEMS leadership meetings.

Maintain at least one group member at the EOC. EOC presence may be modified to "on call" when planning work is not significant (for example, during night shift) as approved by the Incident Commander.

Work closely with Emergency Manager to develop a high level restoration strategy.

- Evaluate the adequacy of response and recommend adjustments as needed.
- Evaluate weather forecasts and other event information to develop contingencies.
- Determine if Catastrophic Emergency Memorandum Account (CEMA) request is appropriate and coordinate with local government officials and Regulatory Affairs on emergency declarations.
- Develop load forecasts and plan sources of energy supply to best meet load demand.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on planning issues.
- Perform other planning activities as directed by the Incident Commander.
- Develop lists of lessons learned for after action evaluation and improvements to plans.

Finance & Administration Group.

The Accounting Supervisor is the primary BVES staff assigned in charge of the Finance and Administration Group. Alternate staff may be assigned include the Energy Resource Manager, Senior Account Analyst, or others as designated by the Incident Commander.

The Finance & Administration Group shall normally be made up of the Senior Account Analyst, Account Analyst, Administrative Support Associate, and other staff as designated by the Incident Commander.

The Finance & Administration Group reports directly to the Incident Commander on all finance and administration issues and coordinates directly with the leaders of the Operations, Logistics and Planning Groups to provide optimal Finance & Administration support to ensure that restoration activities are safe, efficient and effective. Activities associated with Finance & Administration Group include, but are not limited to:

Group leader attends BVES SEMS leadership meetings.
Maintain at least one group member at the EOC. EOC presence may be modified to "on call" when planning work is not significant (for example, during night shift) as approved by the Incident Commander.

Work closely with Operations & Logistics Groups to track expenses (labor, invoices for services, materials consumed, etc.).
Ensure clear guidance provided to groups to ensure expenses properly tracked.
Treat each event as possible Catastrophic Event, which costs could be authorized for recovery.
Execute CUEA administrative requirements as needed.
Work collaboratively with other stakeholder organizations and the General Office as applicable on finance and administration issues.
Perform other finance and administrative activities as directed by the Incident Commander.

Develop lists of lessons learned for after action evaluation and improvements to finance and administration.

2.5. **Plan Changes.** BVES Incident Commander has the authority to modify this plan including the organizational structure as needed to optimally respond to the specific emergency at hand. Specifically, the Incident Commander, must evaluate each emergency situation and determine:

To what extent should the BVES Emergency Organization be staffed.
To what extent should the EOC be activated.

Should additional resources (for example, mutual aid and/or contracted services) be mobilized.

Emergency Response Event Preparations.

Preparations. Emergency Response preparations are a long-term process for which each BVES Department must be constantly ready, especially during the winter months. Preparations for emergency response are best achieved through training on the EDRP, continuous evaluation of the plan, coordination and outreach with external stakeholders, provisioning emergency response materials and equipment, and establishing mechanisms to rapidly bring emergency response resources to the service area such as mutual aid agreements, contracts, and other partnering agreements.

Emergency Response Preparations Checklist. Appendix B, Emergency Response Preparations Checklist, is designed to assist Managers and Supervisors in short-term emergency response preparations.

The President shall direct the execution of the Emergency Response Preparations Checklist based on available forecasting information. In general, it is easier to stand down from a forecasted storm event that does not materialize than to ramp up in the middle of a major storm event. Therefore, erring on the side of being ready is always the better choice. The President may direct the suspension of the Emergency Response Preparations Checklist if the forecast changes and it is no longer warranted.

The checklist is ideally triggered at the 96-hour point prior to a potential emergency response event such as a major forecasted winter storm. However, staff must be flexible and understand not all emergency response events will be accurately forecasted; hence, the implementation time of this checklist may be significantly less than 96-hours. In the event that major outages occur without warning, it is still useful to go through the Emergency Response Preparations Checklist and complete the preparatory checklist items as applicable.

The checklist is designed to be all-inclusive of plausible emergency response to storm events for the BVES service area such as winter snow storms. Therefore, certain preparatory items may not be applicable for all emergency response events; for example, vehicle snow chains may not be required during a loss of import power supply lines from Southern California Edison (SCE). The Utility Manager may direct that certain items on the checklist need not be executed as applicable. Additionally, the Utility Manager may direct new preparatory items be added to the checklist depending on specific impending conditions. The Utility Manager shall use this checklist as applicable when extreme fire threat weather that could result in PSPS conditions is forecasted. The Utility Manager shall keep the President informed of any changes to the checklist.

During after action reviews for emergency response events as well as the annual Emergency Preparedness and Response Plan drill, the Emergency Response Preparations Checklist should be reviewed for adequacy and updated as applicable.

Contingency Operating Procedures. The Field Operations Supervisor shall develop pre-approved switching orders and operating procedures that would most likely to be used in the more plausible loss of supply and outage scenarios. The Field Operations Linemen, the Power Plant Operators, and other applicable BVES Staff should train on these procedures as applicable so that in the event they are needed, the procedures are readily available, approved, and understood by staff. Switching orders and operating procedures should include at a minimum the following:

BVPP Black Start System Line-up Switching Order.
BVPP Black Start Engine Startup Procedures (with and without back-up BVPP generator).
Switching Order to express the Radford SCE Source to Meadow Substation.
Rolling blackout procedure when only Radford SCE Source and BVPP are available (13.4 MW Capacity Limit).

Rolling blackout procedure when only BVPP is available (8.4 MW Capacity Limit).
Load shedding procedures and priorities.
Proactive de-energization of high risk circuits in the event of extreme fire threat weather.

Mobile Emergency Generation. The Utility Manager shall ensure that there is a contingency plan to connect mobile emergency generators to the BVES system to provide emergency power. The contingency plan should at a minimum include the following:

Source at least 5 MWs of mobile emergency generation (may be multiple generators) that may be brought to the BVES service area within 24 hours of being requested. If possible, at least two vendor sources should be identified.
Identify the fuel requirements and replenishment source(s) for the proposed mobile emergency generation.
Identify the locations in the BVES system where the mobile emergency generators would be located and connected to the BVES system.
Identify the connection type and ensure that this is compatible with the sourced mobile emergency generators and the BVES system.
Identify if any networking is required by the supplier for the mobile emergency generators to operate and, if so, how this shall be accomplished.
Identify any protection needed and ensure that it is available between the source mobile emergency generators and the BVES system connection points.
Identify the operating control requirements for the sourced mobile emergency generators (for example, monitoring requirements, startup and shutdown procedures, voltage and load regulation, phase synchronization, operating checks and maintenance, operator labor requirements, etc.) and address how these shall be accomplished (for example, supplier shall operate the mobile emergency generators, etc.).

Material and Equipment. Obtaining material and equipment is always a challenge given that the BVES service area is remotely located and at approximately 7,000 feet in mountainous terrain with only three points of access. The roads present a significant challenge to large trucks under most conditions and all vehicles in wintery ice and snow conditions. Therefore, it is essential to the success of BVES' emergency response plan that certain minimum levels of materials and equipment be always readily available in the BVES service area.

The Utility Manager shall provide the Accounting Supervisor a minimum quantity of T&D equipment and materials to maintain at BVES to allow timely repairs to likely T&D system failures (overhead facilities, underground facilities, and substation equipment). Additionally, the Utility Manager should identify other vital spares to sustain BVPP operations.

The Field Operations Supervisor shall provide the Accounting Supervisor the minimum quantities of materials and supplies necessary to safely operate field crews involved in restoration repairs. These supplies should include items such as traffic control markers and signs, caution cones, portable site lighting, caution lighting, yellow CAUTION tape and red DANGER tape, portable safety barriers, personal protective equipment (PPE), winter and foul weather gear, etc.

All Managers and Supervisors shall ensure that their staff that would be assigned to operate in the field have available to them the appropriate PPE, adequate weather protection (cold weather gear, rain gear, sunscreen and head gear, etc.), and equipment to perform their duties as assigned by the EDRP.

The Buyer and Storekeeper under the supervision of the Accounting Supervisor shall ensure the equipment and materials identified above are stocked to the minimum quantities. Additionally, they shall ensure the identified equipment and materials are readily sourced and may be ordered and delivered in short timeframe.

Vehicles. All Managers and Supervisors are responsible for ensuring that the vehicles and trucks assigned to them and their employees are ready to operate safely and as needed during restoration activities under the anticipated weather and terrain challenges of the BVES services area.

The Accounting Supervisor shall develop a minimum list of equipment for all BVES vehicles to operate safely in the anticipated weather and terrain conditions including snow and ice that are reasonably encountered in the BVES service area (for example, snow tires, snow chains, shovel, first aid kit, light, fire extinguisher, etc.).

The Field Operations Supervisor shall develop a list of any additional equipment necessary for all utility trucks (digger and bucket trucks), work trucks (foreman and Dutyman trucks) and other vehicles used by Field Operations employees to operate safely and as needed in the anticipated weather and terrain conditions that are reasonably encountered in the BVES service area.

The Storekeeper under the direction of the Accounting Supervisor shall coordinate with the applicable Managers and Supervisors to ensure all vehicles and trucks are fully equipped, properly serviced, and ready to safely operate as needed in the anticipated weather and terrain conditions that are reasonably encountered in the BVES service area.

If a vehicle is not properly equipped, in good working order, and/or safe to operate for the current or anticipated conditions, it should be identified as such by the applicable Manager or

Supervisor that is responsible for the vehicle or truck and restricted in use (for example, if a vehicle is not equipped with snow tires and chains, it should not be used in snow conditions).

Contracts for Services. During emergency restoration response activities, outside contracted services may be required to ensure efficient and effective restoration of electric service. However, it is extremely difficult to source and contract out services on short notice during an emergency. Therefore, Managers and Supervisors should identify the critical contracted services that may be reasonably expected to be needed for restoration activities, source providers of these services, and establish emergency contract agreements in accordance with the BVES's procurement policy.

Table 3-1 lists the contracted services that should have pre-arranged emergency contract agreements in place.

Table 3-1: List of Minimum Contingency Contracted Services

Contracted Service	Responsibility	Additional Emergency Requirement
T&D overhead and underground high voltage utility power line construction.	Utility Manager	Must have 24/7 contact. Onsite within 8 hours.
T&D substation and major electrical equipment troubleshooting, repair and replacement services.	Utility Manager	Must have 24/7 contact. Onsite within 24 hours.
T&D work package design and development services.	Utility Engineer & Wildfire Mitigation Supervisor	Onsite within 48 hours.
Civil construction for utility underground infrastructure repair and construction, road and sidewalk repair and construction, retaining wall repair and construction, backhoe services, hauling and other civil construction services.	Field Operations Supervisor	Must have 24/7 contact. Onsite within 8 hours.
Crane and lifting Services.	Field Operations Supervisor	Must have 24/7 contact. Onsite within 8 hours.
Vegetation clearance from high voltage overhead power lines and tree removal.	Field Operations Supervisor	Must have 24/7 contact. Onsite within 8 hours.
Airborne inspection, heavy lift and construction services	Utility Manager	Must have 24/7 contact.
Environmental cleanup and mitigation to oil and hazmat spills.	Accounting Supervisor	ust have 24/7 contact. nsite within 8 hours.
Welding and metal fabrication services.	Field Operations Supervisor	Must have 24/7 contact. Onsite within 8 hours.
Snow removal for BVES Main Facility and Stockyard, substations and other areas as directed.	Field Operations Supervisor	Must have 24/7 contact. Onsite within 4 hours.
Troubleshooting, repair and replacement parts for emergency generators (Main Office and BVPP).	Field Operations Supervisor	Must have 24/7 contact. Onsite within 12 hours.
Mechanical and electrical troubleshooting, repair services and replacement parts for BVPP equipment and support systems (Waukesha Model VHP7104GSI engine/generator sets).	Field Operations Supervisor	Must have 24/7 contact. Onsite within 12 hours.

Utility Truck troubleshooting, repair and support services	Field Operations Supervisor	
Vehicle troubleshooting, repair and support services	Storekeeper	
Diagnostic and technical support services for SCADA and associated network systems.	Senior Technical Operations Support Specialist	

Contracted Service	Responsibility	Additional Emergency Requirement
Diagnostic and technical support services for Outage Management System (OMS) and related applications.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for Interactive Voice Recording (IVR) and related applications.	Customer Service Supervisor	
Diagnostic and technical support services for BVES's phone system.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for BVES's internal and external network and connectivity systems.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for BVES's External Website.	Customer Program Specialist	
Public relations (PR) services	Customer Program Specialist	Must have 24/7 contact. Provide remote PR response within 2 hours
Media advertising services	Customer Program Specialist	

Many of the services listed in Table 3-1 are used in the normal course of BVES operations through already established contracts. Where this is the case, it is advantageous to include any additional emergency response requirements rather than sourcing to different suppliers.

The Administrative Support Associate in coordination with the Utility Manager and Accounting Supervisor shall develop a list of Contingency Contracted Services and file the list in Appendix C, Contingency Contracted Services. The list shall be in tabular format and at a minimum include the following information:

Contractor Entity Name
Services Provided with brief description of any specific emergency requirements
Point of Contact
- Contact phone numbers including afterhours numbers
- Main Office location

The list shall be reviewed and updated by the Administrative Support Associate each quarter.

Where onsite mobilization is required to perform the requested services, Managers and Supervisors should carefully consider the feasibility for the contractor to reach the BVES service area in a timely manner given the remote and mountainous terrain.

When advanced warning or forecasting is available, the Utility Manager may direct prepositioning of equipment and materials to improve the ability of the contractor to mobilize. For example, a contractor for T&D overhead and underground high voltage utility power line construction may be requested to pre-position trucks at BVES ahead of a snow storm.

When advanced warning or forecasting is available, it is generally useful for Managers and Supervisors alert their points of contact for contracted services that there may be an impending requirement for their services.

Mutual Aid. Mutual Aid agreements are an efficient and effective resource multiplier available to BVES restoration efforts. Therefore, it is extremely important that these agreements be maintained current and that staff understand what resources they may provide and how to request the resources.

California Utilities Emergency Association. The California Utilities Emergency Association (CUEA) Mutual Aid Agreement allows member utilities to request and obtain labor, materials, and/or equipment resources from other member utilities in a rapid manner on a reimbursable basis. BVES shall be an active member of CUEA and shall participate in the Energy Committee meetings and activities as feasible. Generally, CUEA meetings and activities provide information on emergency response planning at other utilities and state agencies. Additionally, CUEA is an excellent forum for organizations to discuss best practices. The Utility Manager shall be responsible for managing CUEA mutual aid agreement and shall ensure processes are in place and applicable Operations Staff are trained to:

Inquire about CUEA resources and make formal mutual aid requests in accordance with the CUEA agreement.
Provide mobilization support such as lodging and meals to responding mutual aid crews and other labor resources provided through CUEA.
Direct and manage mutual aid crews and other labor resources provided through CUEA.
Provide logistics support (materials, equipment and other resources as needed) to mutual aid crews and other labor resources provided through CUEA.

The Administrative Support Associate shall ensure CUEA documents are available to the Operations Group and in the EOC.

The Accounting Supervisor shall ensure processes are in place to account for and pay for CUEA mutual aid resources that respond to BVES' aid requests. This shall require close coordination with the Operations Group.

Mountain Mutual Aid Association. The mission of the Big Bear Valley Mountain Mutual Aid Association ("MMAA") is to coordinate and facilitate resources to minimize the impact of disasters and emergencies on people, property, the environment, and the economy. This is accomplished by detailed valley-wide evacuation planning and dedicated support to all involved emergency responders and their agencies. MMAA's vision is to prepare Big Bear Valley citizens, tourists, businesses, and governments to maximize their resistance to disaster through preparedness, mitigation, response, and recovery activities. BVES shall be an active member of MMAA and shall actively participate in the MMAA meetings and activities. This is especially important in establishing strong personal business relationships with key players and stakeholders in the community such that during an emergency event, the BVES Team is working with stakeholders it is already familiar with. **Table 3-2** provides a listing of the MMAA current membership. The Utility Manager shall be responsible for managing MMAA mutual aid agreement and shall ensure processes are in place and applicable Operations Staff are trained to:

Coordinate activities with MMAA.
Request support and resources of MMAA members.

MMAA has the ability to provide a wide range of direct support to BVES restoration activities during emergency response including traffic controls, road-clearing services, coordination with local government agencies, other utilities, and other nongovernmental organizations, and communications with the public. Additionally, one of the most significant strengths of MMAA is its ability to coordinate through its member organizations support and relief for customers experiencing extended sustained major power outages. This may include health and welfare checks, shelters, meals, cooling centers, restroom and shower stations, etc.

Table 3-2: Bear Valley Mountain Mutual Aid Association Membership

Organization		
City of Big Bear Lake Big Bear Fire Department San Bernardino County Fire San Bernardino County Department of Public Health San Bernardino County Office of Emergency Services (OES) San Bernardino County Sheriff's Department San Bernardino County Transportation Authority San Bernardino County Emergency Communications Service (ECS) U.S. Forest Service California Highway Patrol California Department of Transportation	Big Bear Airport Big Bear City Community Services District Big Bear Lake Department of Water & Power Big Bear Lake Municipal Water District Big Bear Area Regional Water Authority Bear Valley Electric Service, Inc. Southwest Gas Bear Valley Community Healthcare District Bear Valley Unified School District Mountain Area Regional Transit Authority	Bear Mountain Ski Resorts Big Bear Chamber of Commerce Big Bear Lake Resort Association Big Bear Valley Recreation & Park District American Red Cross Big Bear Community Emergency Response Team (CERT) Big Bear Valley Community Organizations Active in Disaster (COAD) Big Bear Valley Voluntary Organizations Active in Disaster (VOAD) Civil Air Patrol Salvation Army

Communications Layers and Message Deck. Communications with stakeholders and customers during emergency response is one of BVES' top three priorities. The Customer Service Supervisor with the support of the Customer Program Specialist shall ensure the following:

Multiple layers of communications are established to reach customers. These should include

agreements with local media (newspaper, internet news, radio stations, etc.), BVES Website, BVES social media, Interactive Voice Response (IVR) System, email blast, etc.
Training applicable staff and testing all of the established communications layers.
Leveraging the communications platforms available to other stakeholder organizations. For example, the Big Bear Chamber of Commerce has an email blast channel to its member businesses and the City of Big Bear Lake has an email blast channel to many of its residents.
Developing pre-approved message templates that properly guide staff preparing communications to customers and stakeholders with the necessary information to provide a useful update. For example, pre-staged press releases, website messages, social media messages, IVR messages, etc. on sustained outages may be prepared well in advance of any emergency with "fill-in-the-blanks" for the specific event.

Staff Roster and Recall List. A critical component of successfully implementing the EDRP is the ability to rapidly recall staff as need. Therefore, it is critical that contact information for each staff be maintained up to date and be made available to staff that would execute the recall.

The Administrative Support Associate is responsible for maintaining and updating the BVES Staff Roster and Recall List. This list shall be filed in Appendix D, BVES Staff Roster and Recall List, to the EDRP. This list shall be reviewed for accuracy each quarter by the Administrative Support Associate and updated as needed.

When new staff join or staff terminate their employment at BVES, the Administrative Support Associate shall update BVES Staff Roster and Recall List.

Additionally, when staff change their contact information, it is essential that they inform their Supervisor and the Administrative Support Associate so that the recall roster may be updated.

The recall roster should include at a minimum employee name, home phone, mobile phone, personal email, and address. It is critically important that the roster have a phone number where the employee may be contacted at any time. The address is important because in a major storm it may be safer and more efficient to send a BVES vehicle to pick up staff to respond to the EDRP and staff up the EOC. Personal email is important because an initial group email blast may be sent to set in motion mobilization of the EOC, while calling each staff member is pursued.

The Administrative Support Associate shall develop and update as necessary a group email address for staff using both their personal and work email addresses for recall purposes.

Key External Contacts List. BVES' ability to contact external stakeholders and resource providers is critical to successfully executing EDRP restoration activities.

The Administrative Support Associate in coordination with Managers and Supervisors shall develop the Key External Contacts List and file the list in Appendix E, Key External Contacts

List. The list shall be in tabular format and at a minimum include the following information:

Key External Contact Entity Name
Point of Contact
Contact phone numbers including afterhours numbers
Email
Main Office location
Category of Key External Contact per Table 3-3

The list shall be reviewed and updated by the Administrative Support Associate each quarter.

Managers and Supervisors should provide the Administrative Support Associate updates to the Key External Contacts List as changes occur.

Table 3-3 provides the minimum key external contact categories that should be included in the Key External Contacts List.

Table 3-3: Key External Contacts

Category
State government, agencies and departments
Local government, agencies and departments
Critical Customers
Public Safety Partners
Utilities
Non-governmental organizations (business and community organizations; volunteer relief and aid groups; other disaster relief entities)
Media groups

Emergency Operations Center and BVES Main Facility. Readiness of the EOC and BVES Main Facility to support EDRP restoration activities on short notice is an essential element to successfully executing the EDRP.

The Utility Manager is responsible for ensuring readiness of the EOC as detailed in Section 2.3. Appendix A, EOC Preparedness Checklist, provides a list of equipment, capabilities, materials and supplies that should be available to the primary EOC. The Operations Group should be familiar with this checklist and be trained on setting up the EOC.

Each Manager and Supervisor is responsible for ensuring that facilities and resources under their responsibility are ready to support the EDRP restoration activities.

The Accounting Supervisor is responsible for ensuring the BVES Main Facility is ready to support sustained EOC and EDRP operations to include stocking consumables for EOC and restoration activities, providing staff on-site meals, water and other necessary habitability amenities.

Emergency Response Procedures.

Emergency Response Plan Implementation and Emergency Operations Center Activation. BVES responds to emergencies and outages based on the resource requirements to properly resolve the situation in a safe, timely, efficient and effective manner. When the restoration efforts are beyond the capabilities of the normally assigned Field Operations staff and normal Customer Service resources, the EDRP should be implemented.

Response Levels. There are three basic outage response levels that BVES uses. Level 1 and 2 pertain to the EDRP and Level 3 refers the normal BVES working hours and afterhours Field Operations and Customer Service outage response procedures and processes. When the EDRP is activated, Level 1 or 2 are used to describe level of EOC activation and restoration response process. Level 3 is the normal Service Crew (or Dutyman for afterhours) response process to outages and system problems during the course of normal T&D operations. The response levels to outages and emergencies are summarized in Table 4-1.

Table 4-1: BVES Outage and Emergency Response Levels

Response	Event Type	Action	Comments
Level 1	High Risk Long-term*	EOC fully activated EDRP processes implemented	It is preferred to fully activate EOC and then shift to Level 2 activation, if full response determined to not be necessary.
Level 2	Moderate Risk Short-term	EOC partially activated EDRP processes implemented	Level of EOC activation and EDRP implementation as directed by Utility Manager.
Level 3	Low Risk Short-term	Normal Service Crew/Dutyman and Customer Service processes	These events are normally within the capability of assigned Service Crew or Dutyman to resolve with the normal on call resources.

*Long-term is generally defined as 12 hours.

Plan Activation. The President shall direct activation of the EDRP and, therefore, the EOC and shall also direct the applicable response Level. The President should consider the following in evaluating whether or not to implement the EDRP and, if the EDRP is to be implemented, to what Level (1 or 2) to activate the EOC:

Will resources beyond BVES' normal outage response posture be required and to what extent? Will external resources (mutual aid and/or contracted services be required)?
Will the restoration efforts be long-term (generally 12 hours or greater)? If long-term, how long?
Will the restoration efforts be more efficient if the BVES staff is organized for around the clock customer service and field operations?
Will the restoration efforts require increased management and logistics support beyond that of the Field Operations Supervisor?
Is the outage (or high potential for outage) expected to have significant impact on BVES

customers and/or stakeholders?

Will rapid and close coordination be required with other government and agencies directing response actions to an emergency (for example, Incident Commander for a wildfire in or adjacent the BVES service area)?
Will communications efforts require increased and dedicated resources beyond the normal Customer Service communications posture?

In considering the above factors, the President shall drive to ensure that the BVES response is at the appropriate level to achieve a safe, timely, and prudent allocation of resources in the best interest of customers and other stakeholders.

The EDRP will be directed in response to an extended outage as a result of proactive de-energization (public safety power shutdown) to shut off power in high risk areas when extreme fire conditions present a clear and imminent danger to public safety. The focus of implementing the EDRP in this circumstance would be to improve coordination with local government and agencies and provide affected customers relief resources generally through mutual aid (MMAA) as needed. Specific public safety power shutdown procedures are provided separately in the BVES Public Safety Power Shutdown Plan.

The President shall direct activation of the EOC in situations where an outage has not yet occurred but the likelihood is significant. An example of a high risk situation is a wildfire that has not yet resulted in outages but has the potential to do so and/or may require rapid and close coordination with the Fire Incident Commander.

It is generally preferred to fully activate EOC and then shift to Level 2 activation as conditions warrant. By bringing in the full EOC organization, the staff can be briefed on the situation and then stood down with specific instructions tailored to the Level 2 response requirements.

When the EOC is directed to be activated, the President shall designate staff to utilize Appendix D, BVES Staff Roster and Recall List, to alert employees to staff the EOC. Additionally, a group email should be sent out to staff using their work and personal email address.

When the EDRP is implemented for training, such as for the annual drill, the Utility Manager shall put controls in place to prevent drill activities from interfering and/or confusing staff, customers, and stakeholders with real-world BVES operations.

Essential Elements of Information (EEI). EEIs are key information that the Incident Commander and EOC Group Leaders need in order to make timely and informed decisions on emergency response. The EEIs listed in Table 4-2, Essential Elements of Information, are critical to the BVES Emergency Leadership Team's ability to assess the emergency situation and decision making in emergency response. Therefore, obtaining this information and continually updating it must be a priority for all staff assigned to the emergency response efforts.

Table 4-2: Essential Elements of Information

EEI	Remarks
Potential hazards that impact the safety and health of BVES employees, contracted and mutual assistance personnel, first responders, and the public	**Safety is our top priority.** Therefore, it is vitally important to identify potential hazards so that resources may be properly allocated to assessing, mitigating and eliminating the hazards.
Updated common operating picture based on indications and sensors, forecasts, and the accumulation of information from the field	Maintaining a common operating picture is a primary function of the EOC staff so that each Group is able to provide a coordinated and collaborative uniform response to the emergency. Additionally, the common operating picture leads to consistent messaging with customers and stakeholders based on the best available information.
Facility and equipment assessments and operational impacts to BVES' business operations Status of Power Delivery Systems 34.5 kV sub-transmission system Substations Distribution system Status of Power Supply (**Cause of supply disruptions and estimated time of restoration**) SCE Supplies from Goldhill SCE Supply from Redlands Bear Valley Power Plant Status of Communications Internet connectivity SCADA network BVES work radios Land line phones Cell phones Internal network connectivity Weather station network BVES Website BVES Social Media Status of IT Applications CC&B IVR/two-way text OMS GIS applications SCADA Status of facilities, equipment, and materials Emergency Operations Center BVES Main Office BVES Yard Work trucks and vehicles Poles, wire, transformers and other material	Identifying causes of power delivery system (T&D) outages and supply disruptions is essential to determining the proper restoration actions to be taken. Maintaining accurate status as conditions in the field change and restoration activities progress throughout the emergency response is key to ensuring restoration resources are properly allocated and optimized at all times. Developing **estimated time of restoration (ETR)** is critical information that our customers and stakeholders need in order for them plan their responses and mitigations to the outage. ETRs must be updated as they change. Communications are often the weak link in emergency response. During an emergency some communications may be degraded and alternate systems may be necessary. Therefore, understanding the status of communication systems is critical to ensuring connectivity with field crews, damage assessment teams customers, and stakeholders. Many utility activities rely upon IT systems for rapid and efficient response. These systems are also susceptible to degradation during an emergency and workarounds may be necessary. Therefore, identifying IT problems and/or limitations is vital to directing effective restoration activities. As a result of the emergency or for other reasons, facilities and equipment may be degraded and material availability may be limited. Therefore, knowing the status of facilities, equipment, and materials is essential to developing restoration actions.

Status of contracted and mutual aid assistance requests	Outside line crew assistance, tree trimming services, crane support, snow removal services, civil construction services, and other outside assistance is often critical to successfully executing restoration activities. Therefore, is critical to fully understand: Which entity (or entities) are providing resources? What specific resources they are providing (equipment and personnel)?

EEI	Remarks
	How and when will they arrive at BVES's service area? What logistic support will they require?
Limitations on access and transportation due to flooding, roadway damage, debris, or other closures	Access to BVES's service area under normal circumstances is limited. During an emergency, it is plausible that some or all of the access may be interrupted, which will significantly impact the ability to bring resources to BVES. Additionally, access to certain areas within the service area may be severely impaired due to the emergency. Therefore, it is critical that the EOC Team fully understand access limitations and have backup plans in place.
Interdependencies between BVES, government agencies, other utilities (water, gas, and electric), and critical infrastructure	Outages may have significant impact on government agencies, other utilities (water, gas, and electric), and critical infrastructure; especially, when their backup systems fail. Therefore, the EOC Team must be fully aware of how outages are impacting the area and coordinate a prioritized restoration plan that fully considers the above.
BVES staff supporting other agencies (for example, Incident Commander representative)	Imbedding a BVES representative with the on scene Incident Commander and/or local government EOCs (City or County) has proven to be highly effective in coordinating emergency response actions. The EOC Team must communicate frequently with the imbedded BVES representative to ensure coordinated and uniform emergency response.

Restoration Strategy. Outage events and emergencies are rarely similar in all respects; therefore, this general restoration strategy is constructed to provide the EOC Team with a scalable and flexible restoration strategies that can be employed as required to deal with the unique aspects of each major outage and emergency event.

Restoration Strategy Assumptions. Restoration strategies and guidance in the EDRP assume that the BVES system is in its **normal winter line-up** as follows:

Bear Valley Power Plant (BVPP) is available for normal full power operations (8.4 MW).
Goldhill SCE sub-transmission power lines and facilities from Cottonwood (Doble, Cushenberry, Goldhill Switch Station, and Ute 1 & 2) are fully operational and connected to the BVES system at the Shay and Baldwin Auto-Re-closers (34 MW).
Radford SCE sub-transmission power lines and facilities from Zanja are fully operational and connected to the BVES system at the Radford Auto-Re-closer (5 MW).
BVES T&D systems are in the normal system line-up.

Therefore, staff must ensure that when implementing guidance provided in the EDRP that they fully understand the current line-up of the BVES system and, if there are deviations to the normal winter line-up, they must properly account for these deviations in their restoration actions. It should be noted that under normal conditions, the Field Operations Supervisor controls the system line-up and during EOC activation the system line-up is controlled by the SOS.

Restoration Priorities. The Utility Manager shall direct the specific restoration priorities keeping safety (public and worker) as the top priority. In most cases, based on best available information regarding the situation and available restoration resources, resources shall be dispatched to restore systems to achieve the following restoration priorities:

Public safety in the affected areas;
Worker safety in performing the restoration work;
Critical infrastructure Sheriff's Department, hospital, Fire Department, key City & County facilities, other utility facilities (water, sewage, gas, communications), Airport, Traffic Control, Incident Commander Site, Incident Base Camp, Incident Evacuation Centers, communications (Spectrum and various cell providers), radio stations;
Major commercial activities critical to **continuity of community services**: gas stations, food stores, supply stores, repair shops, eateries and lodging facilities to support outside first responders (CAL FIRE), as well as financial institutions.
Medical Baseline Customers and Access and Functional Needs Customers
Number of customers affected; and
Length of time customers have been without power;

Restoration Progression. In directing restoration efforts to achieve the priorities of Section 4.2.2 above, the Operations Group shall generally find it most efficient to dedicate restoration resources to restoring the following types of facilities in the prescribed order to optimally restore electric service:

Energy supply sources Southern California Edison (SCE) supply lines, Bear Valley Power Plant (BVPP), etc.
Sub-transmission circuits (34.5 kV)
Substations
Distribution circuits (4 kV)
Feeders
Distribution transformers
Individual customer service lines

Taking into account restoration priorities and progression, Table 4-3 below provides guidance on the restoration priorities for sub-transmission circuits, substations, and distribution circuits. This guidance must be tempered by many factors including the actual cause of the outage(s), available resources, time to conduct repairs, access to repair sites, etc. Therefore, the Utility Manager must have wide discretion when developing the specific restoration priorities and may choose to deviate from the general guidance.

Table 4-3: Restoration Priorities for Sub-Transmission Circuits, Substations, and Distribution Circuits

Priority	Sub-Transmission Circuit	Substation	Distribution Circuit		Comments
1	Baldwin	Meadow	Garstin		Key critical infrastructure. Connects BVPP
2	Shay/Radford	Pineknot Village Maltby Division	Interlaken Boulder Harnish Country Club	Georgia Paradise Erwin Lake Castle Glen	Additional critical infrastructure Major commercial activities & airport Large number of residential customer.
3	NA	Moonridge Maple Bear City Fawnskin Palomino	Eagle Lagonita Fox Farm Clubview Sunset	Goldmine Holcomb Pioneer Sunrise	Mostly residential customers
4	NA	Bear Mountain Summit Lake	Geronimo Skyline	Lift Pump House	Mostly interruptible customer.

<u>Loss or Significant Reduction of Energy Supply</u>. BVES normally imports all of the supplies necessary to meet customer demand via SCE power lines and augments the supplies using the BVPP when the maximum capacity from the SCE Cottonwood lines are reached. Table 4-4 provides information on BVES system sources of power.

Table 4-4: BVES System Sources of Power

Source	Capacity	Comments
Goldhill: Includes SCE lines and facilities from Cottonwood (Doble, Cushenberry, Goldhill Switch Station, and Ute 1 & 2).	34 MW	Connected to the BVES system at the Shay and Baldwin Auto-Re-closers
Radford: Includes SCE line (Bear Valley) and facilities from Zanja.	5 MW	Connected to the BVES system at the Radford Auto-Re-closer
Power Plant: Includes Bear Valley Power Plant (BVPP) generation equipment and facilities.	8.4 MW	Seven 1.2 MW natural gas fired engines
Net Energy Metering & Distributed Energy Resources	3.3 MW	Distributed throughout system. Limited to day-light production only

Table 4-5 provides guidance on some of the more likely loss of energy supply scenarios to the BVES Service Area. Each of these scenarios assumes a complete loss of the affected power source(s). However, it should be realized that it is also possible that certain power sources may be degraded providing some limited capacity instead of being completely lost. In these cases, the Operations Group should follow the framework provided in Table 4-5 modified to take into account the limited supply capacity of the degraded power source(s).

Table 4-5: Actions for Loss of Supplies

Actions	Loss of all SCE Supplies (Goldhill & Radford)	Loss of SCE Goldhill Supplies	Loss of SCE Radford Supply	Loss of BVPP
Contact and coordinate with SCE.	Call SCE Lugo Substation and SCE Control Center Colton. Obtain system status, actions in progress or scheduled and	Call SCE Lugo Substation. Obtain system status, actions in progress or scheduled and ETR.	Call SCE Control Center Colton. Obtain system status, actions in progress or scheduled and ETR.	NA
Actions	Loss of all SCE Supplies (Goldhill & Radford)	Loss of SCE Goldhill Supplies	Loss of SCE Radford Supply	Loss of BVPP
	estimated time of restoration (ETR).			
Assess situation	Based on ETR for all or partial energy supplies and demand, take all or some of the actions specified below as appropriate.	Based on ETR for all or partial energy supplies and demand, take all or some of the actions specified below as appropriate.	If situation is long-term, work with interruptible customers to coordinate timing of their loads to reduce or eliminate interruptions.	If situation is long-term, work with interruptible customers to coordinate timing of their loads to reduce or eliminate interruptions.
Activate EOC	Yes – Level 1 Event	Yes – Level 2 Event	No – Level 3 Event	No – Level 3 Event
Switching Operations	Line-up system for BVPP Black Start Procedures	Express Radford to Meadow.	Shift Village Substation to Shay Line	NA
Dispatch BVPP	Execute BVPP Black Start Procedures and Start up Enginators one at a time being careful to not exceed the load capacity.	Start up Enginators one at a time being careful to not exceed the load capacity.	Start up Enginators as needed based on load.	Conduct actions to repair BVPP.
Interrupt interruptible customers	Will be required to meet demand.	Will be required to meet demand.	Possibly required to meet demand. Work with customers to coordinate demand to reduce or eliminate interruptions.	Possibly required to meet demand. Work with customers to coordinate demand to reduce or eliminate interruptions.
Rolling blackout procedures	Will be required to meet demand.	Will be required to meet demand.	Not likely required.	Not likely required.
Contract emergency mobile generation	Consider based on ETR if greater than 24 hours.	Consider based on ETR if greater than 24 hours.	Not likely required.	Not likely required.
Public Engagement	Work with community and stakeholder to reduce non-essential loads. Keep customers and stakeholders informed of ETR and rolling blackouts.	Work with community and stakeholder to reduce non-essential loads. Keep customers and stakeholders informed of ETR and rolling blackouts.	Not likely required.	Not likely required.
Compliance reporting	Conduct CPUC Major Outage Report per GO-166 due to greater than 50% of customers experiencing outage.	Conduct CPUC Major Outage Report per GO-166 due to greater than 50% of customers experiencing outage.	Conduct CPUC Major Outage Report per GO-166 if media coverage expected or occurs.	Not likely required.
Load forecasting	Energy Resources to provide detailed hourly forecasts and make recommendations to support load with BVPP and mobile generation.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load with BVPP and mobile generation.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load without Radford Line.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load without BVPP.

<ins>Downed Wire Response</ins>. During a major storm, BVES may receive many trouble calls reporting primary and service lines down throughout the service area. Wires down that present an imminent fire or electrocution hazard or are identified as being primary distribution line voltage

shall receive top priority. In general, higher priority shall be assigned to calls involving wires blocking state highways or wires down on buildings or vehicles. Personnel investigating downed wire shall determine the wire type (primary, secondary or service conductor) and take actions as directed by the SOS and per Table 4-6, Downed Wire Response.

Table 4-6: Downed Wire Response

Conductor	Action
Primary	
Conductor	**Action**
	If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible (this may require dropping the main BVES supply transmission lines remotely). Warn others to stay clear. Isolate the area by setting up CAUTION tape and traffic cones and barriers. Call into the EOC the exact location (address and pole numbers). If wire is energized, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. Once line is de-energized, area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS.
Secondary	If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible. Warn others to stay clear. Isolate the area by setting up CAUTION tape and traffic cones and barriers. Call into the EOC the exact location (address and pole numbers). If wire is energized and located near a school, high pedestrian area, on a main roadway, or near a conductive structure, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. Once line is de-energized or it is determined that the area is low risk and the area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS.
Service	If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible. Warn others to stay clear. Isolate the area by setting up CAUTION tape and traffic cones and barriers. Call into the EOC the exact location (address and pole numbers). If wire is energized and located near a school, high pedestrian area, on a main roadway, or near a conductive structure, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. Once line is de-energized or it is determined that the area is low risk and the area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS. If the line is disconnected from the pole, it is not necessary to isolate the area. Simply call the situation into the EOC and proceed to next location as directed by SOS.

<u>Sub-Transmission and Distribution (T&D) Casualties</u>. The most common cause of outages for the BVES services area are casualties to T&D facilities resulting in a major outage, multiple outages of varying sizes, and/or some combination thereof. Restoration from these outages is mostly dependent on the available resources, which can quickly be overwhelmed if not properly managed.

The Operations Group shall prioritize restoration activities and resource allocation according to the general priorities identified in Section 4.3.2 and shall restore T&D facilities in the order listed in Section 4.3.3 to achieve these priorities. In establishing restoration priorities, public and worker safety is always the top priority.

SOS balances efforts to conduct repairs while attempting to restore service to as many customers as possible by isolating the damaged facilities to as close to the damage as feasible with the goal of minimizing the number of customers affected by the outage. The SOS should evaluate the time to isolate the damage and restore service to some customers against the estimated time to repair the damage and restore power to all customers. The most efficient and effective course of action shall depend on the extent of damage, availability of resources to conduct repairs, and availability of resources to perform switching operations.

Once damaged facilities are identified to the Operations Group, the SOS shall have the facilities field checked by the Damage Assessment Team (DAT) or by other competent staff, such as nearby field crews, to determine the extent of required repairs needed as well as the ability to isolate the damage and restore power to as many customers as possible.

Based on the results of the field check, the SOS shall:

Determine the priority to repair the damages;
Direct switching operations to restore power to as many customers as possible, if feasible;
Determine the repair work scope (for example, temporary repair such as shoring up damaged facilities or permanent repair per BVES construction standards, etc.);
Assign Engineering Planning resources as deemed necessary (for example, perform pole loading assessments for pole replacements);
Schedule Field Crew resources as applicable;
Direct assigned Field Crew to draw necessary materials and conduct repairs;
Inform and periodically update the Public Information Group and Emergency Service Representatives so that they may keep customers and stakeholders informed; and
Close out or cause to be closed out the applicable Field Activity.

EOC and Emergency Response Workflows. The EOC and emergency response workflows are designed to:

Develop and maintain an accurate common operational picture.
Continually assess damage and develop optimal restoration response.
Dispatch resources for emergency restoration activities.
Manage field activity reports.
Keep customers and other stakeholders informed.
Ensure restoration activities are properly resourced.

<u>EOC Setup</u>. The EOC shall be set up in accordance with Appendix A, EOC Preparedness and Setup Checklist. The Strategic Operations Supervisor in consultation with the Emergency Manager shall direct which applications are to be displayed on the available

large screens and projector and how the white board shall be utilized. The displays should be optimized to provide EOC staff and decision makers an accurate common operational picture based on the best information available.

EOC Staffing. The following staff shall normally be present or represented as applicable in the EOC:

Incident Commander
Public Information Group
Emergency Manager
Strategic Operations Supervisor (SOS)
System Monitor
- Damage Assessment Team (DAT) – when not assigned to the field

Emergency Service Representative (ESR) – normally located in the Customer Service area to reduce noise level in EOC
Engineering Technical Support
IT Operations Support – normally located in IT spaces
Logistics Group
Planning Group
- Finance & Administration Group

Managing Field Activities. The Emergency Manager may find it useful to manage Field Activities by utilizing a spreadsheet to track each Field Activity by recording and sorting the following information:

Field Activity Number
Date
Time
Location
Circuit
Substation
- Status (Unassigned/Crew Assigned/Completed)
- ETR
- Grouping (often multiple Field Activities are resolved when a common fault/damage location is repaired)
- Customer call back
- Comments
- Other information as deemed necessary by the Emergency Manager

Workflows. The EOC shall process incoming damage reports and service request as Field Activities using the workflows shown in Appendix F, Emergency Response Workflows. The emergency response workflows are provided for Level 1 and 2 activations. For reference, the Level 3 (normal service response) is also provided. The Utility Manager may direct deviations to the workflows if it is determined that a more effective and efficient workflow process may be achieved. When conducting after action reviews for emergency response events as well as the annual Emergency Preparedness and Response Plan drill, the Appendix F, Emergency Response Workflows, should be evaluated for possible changes and improvements, and updated if deemed appropriate.

Situation Report. Developing a common operational picture is an important function of the EOC staff in order to ensure decision making is optimal. One essential tool in developing the common operational picture is to periodically update a Situation Report (SITREP). Appendix G provides an example SITREP. The SITREP should be updated by the SOS at least once per shift and more often if conditions are rapidly changing. The SITREP should be displayed in the EOC and sent to the Incident Commander, Public Information Group, EOC Group Leaders, Emergency Service Representatives, and others as deemed appropriate by the Emergency Manager.

Damage Assessments. The Damage Assessment Team(s) shall be dispatched from the EOC to investigate Field Activities and other damage reports. They shall complete a Damage Assessment form and provide it to the SOS. Appendix H provides a sample Damage Assessment Form. If they have several sites to visit, they may consider taking a picture of the completed form and sending to the EOC. Also, the DAT should take as many pictures needed to identify the damage and allow for the Engineering Team to plan the necessary repair work for the line crews. For example, the DAT should take pictures of any damaged equipment and facilities so that material may be pulled and staged for the line crews. Also, the DAT may make use of tools such as FaceTime to communicate with the EOC and provide the EOC a complete assessment of the damage conditions and the iRestore First Responder app to quickly make a basic report with location and a picture.

Work Orders. The SOS shall direct the use of Work Order jackets for the more complex repairs so that the scope of work performed and material and equipment utilized is properly documented. These Work Order jackets should include one-line diagrams and material sheets as applicable along with specific instructions from Engineering & Planning if warranted. Appendix I provides a sample Work Order Jacket.

Resources. Using best available information, the Utility Manager shall continually assess the following:

Resources necessary to execute the restoration activities in a safe, effective and efficient manner;
Available resources in the Service Area;
Gaps in resource availability to execute the restoration activities in a safe, effective and efficient manner; and
When resources from outside entities such as CUEA mutual aid and/or contracted resources may be released.

Based on the above assessments, the Utility Manager shall coordinate with the Logistics Group leader to request additional resources as necessary to fill resource gaps and to relinquish resources when no longer required. Possible resources in addition to BVES resources include CUEA mutual assistance, contracted services and Big Bear Valley Mountain Mutual Aid Association.

California Utilities Emergency Association (CUEA). The Utility Manager shall determine if gapped resources are best provided by utilizing the CUEA Mutual Aid Agreement, which allows member utilities to request and obtain labor, materials, and/or equipment resources from other member utilities in a rapid manner on a reimbursable basis. The specific process for requesting and receiving mutual aid from member utilities is provided in the CUEA Mutual Aid Agreement. Table 4-7, CUEA Mutual Assistance Process, provides a summary of the process for requesting and receiving CUEA mutual assistance.

Table 4-7: CUEA Mutual Assistance Process

Process Step	Responsibility	Amplifying Comments
Determine if CUEA Mutual Aid **may** be required	Utility Manager	The Operations Group evaluates if CUEA resources may be required and if there is a possibility, this should be communicated to the Logistics Group.
Issue a "Mutual Assistance Inquiry Only"	Logistics Group Leader	Providing the CUEA Staff with a Mutual Assistance Inquiry Only allows the CUEA to alert member utilities so that they may evaluate which resources are available without incurring costs. This request is best made via email but it may also be made via phone call. The following information should be included in the inquiry: BVES Contact Name BVES Contact Phone Number BVES Contact Email Type of Emergency Type of Assistance Requested Desired Date & Time Needed Additional Details or Comments
Determine that CUEA Mutual Aid **is** required.	Utility Manager	Obtain Incident Commander's authorization to proceed with CUEA mutual aid request and then, request Logistics Group make arrangements.
Issue a "Mutual Assistance Formal Request"	Logistics Group Leader	Send the CUEA Staff a Mutual Assistance Formal Request with following information: BVES Contact Name BVES Contact Phone Number BVES Contact Email Type of Emergency Type of Assistance Requested Desired Date & Time Needed Additional Details or Comments This request is best made via email but it may also be made via phone call and then followed up by email.

Pre-arrival coordination	Logistics Group Leader	Once a member utility (referred to as “Assisting Party”) agrees to provide resources, the Logistics Group shall work with the Assisting Party point of contact to facilitate all logistics arrangements to include mobilization through demobilization. Specifically, the following information should be obtained: Date and estimated time of arrival of the Assisting Party resources Name and contact information of the Assisting Party’s Team leader Names and contact information of the Assisting Party Team members How lodging will be handled [1] How meals will be handled [2]
Mutual Assistance Agreement Letter	Finance & Administration Group Leader	Once the pre-arrival information is verbally agreed upon, the Finance & Administration Group shall draft the Mutual Assistance Agreement Letter, route it to the Utility Manager and Logistics Group Leader for review and to the Incident Commander for approval signature. Appendix G, Mutual Assistance Agreement Letter, provides a sample letter.

Process Step	**Responsibility**	**Amplifying Comments**
Setup Assisting Party in BVES Accounts Payable System	Finance & Administration Group Leader	Coordinate with the Assisting Party to ensure they are able to invoice BVES in accordance with the CUEA Mutual Aid Agreement. Provide the Assisting Party invoicing instructions to ensure timely payments.
Mobilization	Logistics Group Leader	Coordinate with Assisting Party Team Leader and local facilities to ensure lodging is ready and assist in resolving any arrival issues such as providing information on access to Big Bear Lake, chain requirements and any other travel support (such as permission to pass through areas that may be closed to general public).
Arrival Meeting	Utility Manager and Logistic Group Leader	Upon arrival of the Assisting Party, the Utility Manager and Logistic Group Leader shall meet with the Assisting Party Team Leader, introduce key staff, and go over the following: Safety procedures[3] Coordination meetings[4] Communications[5] Work controls and construction standards[6] Material usage[7] Situation update[8]

Tour of Facilities	Utility Manager	Following the Arrival Meeting, the Utility Manager shall have a BVES employee provide the Assisting Party with a brief orientation tour of key facilities essential to supporting their work including the following: EOC Warehouse Stockyard Where to park trucks Material disposal Hazmat disposal Other logistics support (for example, where to fuel trucks)
Demobilization and Departure Out Brief	Utility Manager and Logistic Group Leader	Ensure lodging checkout is completed and bills are paid. Copy receipts. Review material used by Assisting Party and resolve any documentation issues. Discuss any lessons learned or areas for improvement to allow the Assisting Party to be more effective in the future.
Compensation	Utility Manager and Accounting Supervisor	Coordinate with Assisting Party to review invoices in accordance with the CUEA Mutual Aid Agreement with all of the supporting documentation. The Utility Manager should be the approving manager for the invoices.

Notes:

[1]It is BVES's responsibility to make lodging arrangements; however, an Assisting Party may desire to make lodging arrangements on their own and be reimbursed per the Mutual Aid Agreement.
[2]It is BVES's responsibility to provide meals; however, an Assisting Party may desire to make meal arrangements on their own and be reimbursed per the Mutual Aid Agreement.
[3]Review BVES safety procedures to include tailboard policy and documentation, grounding policy, lock-out/tag-out policy, confined space policy and the BVES Accident Prevention Manual.
[4]Agree upon how the Assisting Party shall interact and receive direction on work from the Operations Group. Sometimes it might be efficient for the Assisting Party to have the Team Leader spend time in the EOC with the Operations Group and out in the field with the Assisting Party crews. Other options include having the Crew Forman check-in before and after each shift.
[5]Establish lines of communications with the Assisting Party Team Leader and crews. They may include cell phones and/or BVES provided radios.
[6]Brief the Assisting Party on BVES work controls including how work will be directed and construction standards used by BVES. Ensure Assisting Party understands what they are permitted to do and when they must seek Engineering approval for any deviations.
[7]Brief the Assisting Party on BVES material control and documentation procedures. Also, agree upon how to replenish truck stock.
[8]Brief the Assisting Party on the current situation, damage assessments and services that the Assisting Party shall be required to perform. This is an excellent opportunity to develop an initial game plan with the Assisting Party.

<u>Contracted Services</u>. Contracted Services as listed in Table 3-1 should be in place such they may be readily requested. The Utility Manager shall determine which contracted services are needed and the specific scope of work and provide this information to the Logistics Group Leader. The Logistics Group Leader shall contact the requested contracts and make the arrangements to receive the services. Appendix C, Contingency Contracted Services, provides contact information for anticipated contract services.

The Logistics Group shall work with the contractor(s) to establish the specific estimated time of arrival, mobilization and demobilization support needed, and the onsite contractor supervisor/foreman contact information.

Upon arrival of contracted crews, the Utility Manager, Field Operations Supervisor, and Logistic Group Leader shall meet with the contractor supervisor, introduce key staff, and go over the following:

Safety procedures: Review BVES safety procedures to include tailboard policy and documentation, grounding policy, lock-out/tag-out policy, confined space policy and the BVES Accident Prevention Manual.

Coordination meetings: Agree upon how the contractor shall interact and receive direction on work from the Operations Group. Sometimes it might be efficient for the contractor to have the supervisor spend time in the EOC with the Operations Group and out in the field with the contractor crews. Other options include having the Crew Forman check-in before and after each shift.

Communications: Establish lines of communication with the Assisting Party Team Leader and crews. They may include cell phones and/or BVES provided radios.

Work controls and construction standards: Brief the contractor on BVES work controls including how work shall be directed and construction standards used by BVES. Ensure contractor understands what they are permitted to do and when they must seek Engineering approval for any deviations.

Material usage: Brief the Assisting Party on BVES material control and documentation procedures. Also, agree upon how to replenish truck stock.

Situation update: Brief the contractor on the current situation, damage assessments and services that the contractor shall be required to perform. This is an excellent opportunity to develop an initial game plan with the contractor.

Following the Arrival Meeting, the Utility Manager shall have a BVES employee provide the contractor with a brief orientation tour of key facilities essential to supporting their work including the following:

EOC
Warehouse
Stockyard
Where to park trucks

Material disposal
Hazmat disposal
Other logistics support (for example, where to fuel trucks)

Once the Utility Manager releases the contractor from providing further services, an out brief meeting shall be conducted with the contractor supervisor, Utility Manager and the Logistics Group Leader to ensure the following: lodging checkout is completed and bills are paid (if BVES handled mobilization); review material used by contractor and resolve any documentation issues; and discuss any lessons learned or areas for improvement to allow the contractor to be more effective in the future.

If a contract is not in place for contracted services that are determined to be necessary for emergency response actions, the Utility Manager may direct, with the President's prior approval, that emergency contracting procedures per the BVES's procurement policy be executed to the obtain the required services. Any verbal service requests should be followed up as soon as feasible in writing (normally by email) by the Logistics Group with the applicable contractor. The email should include the scope of work and price. This should then be followed up with the appropriate procurement documents (for example, contract, service purchase order, etc.).

<u>Big Bear Valley Mountain Mutual Aid Association (“MMAA”)</u>. While MMAA does not have power line construction and repair resources, they do have access to significant support resources including traffic controls, road clearing services, coordination with local government agencies, other utilities, and other nongovernmental organizations, and communications with the public. Additionally, one of the most significant strengths of MMAA is its ability to coordinate through its member organizations support and relief for customers experiencing extended sustained major power outages. This may include health and welfare checks, shelters, meals, cooling centers, restroom and shower stations, etc. Therefore, when the Utility Manager determines that some of these resources are needed, he/she shall inform the Logistics Group Leader who shall coordinate with MMAA in accordance with the MMAA Agreement to request and obtain the desired resources. Coordination with MMAA supplied resources should include Point of Contact, resource estimated time of arrival, appropriate briefings and facility tours by the Operations Group (use the guidance in Section 4.3.1), and agreement on reimbursement if applicable.

Catastrophic Events Memorandum Account (CEMA). CEMA is a process to establish an account to allow utilities to recover the incremental costs incurred to repair, restore or replace facilities damaged during a disaster declared by the appropriate federal or state authorities. If a catastrophic event is declared a state of emergency by the state or federal government, then utilities can record costs caused by the event in this memorandum account. It should be noted that the utility cannot record or request recovery of costs incurred before the date the event is declared a state of emergency. By recording these costs, the utilities can later ask for recovery of these costs from the Commission. The CPUC then reviews these costs and approves them as appropriate.

Anytime the EDRP is activated, accurate records of expenses, labor hours, materials and other costs incurred during the recovery from the disaster shall be maintained such that the incremental costs of recovery efforts may be documented in the event CEMA is invoked. The Finance and Administration Group shall provide specific guidance to Staff to ensure accurate records are maintained. Note that often a state of emergency is declared after the event and recovery have transpired, so each EDRP activation should be treated as a CEMA event.

The President shall coordinate with the Regulatory Affairs Manager to ensure that after a state of emergency occurs and BVES begins booking costs resulting from the event, that a letter is sent to the CPUC Executive President within 30 days. The letter shall provide not only the details of the disaster but also an estimate of the costs to be incurred. The Finance and Administration Group shall develop the estimate for the letter with input from the Operations Group.

Regulatory Affairs Manager shall request cost recovery of the CEMA in a formal proceeding. The Utility Manager with assistance from Accounting Supervisor shall provide the necessary details to support Regulatory Affairs in the CEMA filing.

Evacuation. In the event public officials declare an evacuation order, for all or parts of the Big Bear Valley area, staff's first priority is to address the immediate needs and safety of themselves and family, and once that is taken care of then each employee has a role to play as follows.

Critical Workers**.** Certain staff are considered Critical Workers and are issued an Emergency Pass by the San Bernardino County Sheriff's Department. The Emergency Pass is only to be used for BVES work and in accordance with local authority instructions. The Emergency Pass should never be used for personal reasons. BVES Critical Workers are:

President
Utility Manager
Field Operations Supervisor
Utility Engineer & Wildfire Mitigation Engineer
Senior Technical Operations Support Specialist
All Linemen
Field Inspector
Substation Technician
Meter Technician
Power Plant Operators
Other staff as designated by the Utility Manager

Every two years the Administrative Support Associate shall request new Emergency Passes for the BVES staff classified as critical workers. Also, when new staff arrive the Administrative Support Associate shall obtain an Emergency Pass for them if they are classified as critical workers.

Evacuation Order. In the event government authorities declare an evacuation order for the Bear Valley area, all staff shall follow the evacuation procedure. For partial evacuation orders, the Utility Manager shall evaluate the extent and impact of the partial evacuation and determine if this procedure should be executed and if modifications to the procedure are warranted. For example, an evacuation order for Fawnskin only would likely result in BVES implementing its EDRP and staffing its EOC, the evacuation procedures would likely not need to be executed.

Utility Manager shall:

Direct all non-evacuated staff actions.
Implement the EDRP.
Consult the local government Incident Commander (IC) and/or applicable Emergency Operations Center (City of Big Bear Lake or San Bernardino County OES) and determine the desired condition of the distribution system and any support needed.
Place the distribution system in a safe condition while supporting as practicable the IC's

efforts.
Determine the necessary support staff required to safely operate the system and in consultation with the local government IC where they should be located. If the local government IC determines support staff may safely be located at the BVES Main Office, then that is preferred. If it is not safe to remain at the BVES Main Office, the BVES support staff shall relocate to the Base Camp being utilized by the IC or other designated area as agreed upon by the IC.
Inform the President of the plan.
Provide instructions to Critical Workers.
Release any staff who are no longer needed and direct them to safely evacuate.
When the evacuation order is lifted, direct restoration activities as needed and the return to normal operations.

Staff classified as Critical Workers shall:

Report to the designated area as directed by the Utility Manager. Support staff relocating to the Base Camp or other designated area shall bring utility trucks and equipment as determined necessary by the Utility Manager.
Dispatch to perform tasks as directed by the Operations Group. BVES staff dispatched to perform tasks in the evacuated areas shall always perform these tasks in at least pairs and shall conduct a communications and status check with the Operations Group at least hourly.
BVES Staff representative should be assigned to the IC's Base Camp to coordinate any support needed. BVES Representative assigned to the local government IC Base Camp or an EOC shall be designated by the Utility Manager, knowledgeable of the BVES distribution system, and have direct access to the Utility Manager such that IC and/or EOC requests are not delayed.
Consideration shall also be given to providing BVES Staff representative to supporting Emergency Operations Center (City of Big Bear Lake or San Bernardino County OES).
Released critical workers in the affected areas should evacuate in a safe manner off the mountain in a safe and orderly manner following local authority instructions. Report to the General Office in San Dimas, CA or other area as designated by the Energy Resources Manager.

Non Critical Worker Staff in the affected areas should evacuate in a safe manner off the mountain in a safe and orderly manner following local authority instructions. Report to the General Office in San Dimas, CA or other area as designated by the Energy Resources Manager.

Energy Resources Manager shall:

Direct all evacuated staff actions.
If the General Office is not to be used as the evacuation point, designate a suitable area for evacuated staff to gather.
Perform an accounting of the whereabouts of all BVES staff. Inform the President.
Setup remote support EOC and establish the Planning, Logistics, and Finance & Administration Groups with available staff.

Establish continuous and reliable communication lines with Operations Group remaining in the service area.
Provide resources as requested by the Operations Group.
Provide updates to President, Regulatory Affairs, and Senior GSWC Staff.
Make preparations to obtain utility mutual assistance via the California Utilities Emergency Association (CUEA) and/or contracted Linemen as determined necessary by the Operations Group.
When the evacuation order is lifted, coordinate with the President and Utility Manager the orderly and safe return of staff to the service area.

Customer Supervisor shall:

Establish remote customer service support.
Update public information media as applicable (press releases, website and social media updates, IVR messages, etc.).

End State. The Utility Manager shall direct the transition from emergency response operations under this plan (Level 1 or 2) to normal operations (Level 3) when the following conditions are met:

BVES system is no longer at risk for continued disruptions due to the incident.
BVES power supplies are have been restored to meet service area load demand and are evaluated as reliable.
BVES sub-transmission system is restored to meet service area power delivery needs and is evaluated as reliable.
BVES substations and distribution systems are restored to meet service area power delivery needs and are evaluated as reliable.
Response crews have been demobilized.
System issues and problems are within the normal Level 3 response capabilities.
Long-term customer support has been established as necessary (for example, following a declaration of a state of emergency because a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service) and is capable of being properly managed by the normal supervisory element.

Generally, the transition from Level 1 shall be progressive to Level 2 as emergency response requirements wind down and then to Level 3.

After Action Reports. Once the incident is officially terminated, the Utility Manager shall schedule and conduct formal hot washes/debriefing sessions with applicable staff and have an After Action Report prepared. The After Action Report should include:

Dates/times of the incident
Description of the incident
Level of plan activation and if the EOC was staffed

Records of public communications that were performed
List of damages to system

- List of personal deaths, injuries, and other accidents associated with the incident
- List of external (contracted and mutual aid) resources utilized
- Develop incremental cost of emergency response actions
- Lessons learned
- Evaluation on whether or not the plan was properly followed
- Specific improvement actions including assignment of responsibility to complete and due date

A thorough follow-up includes reviewing all plans and procedures, making the necessary revisions from lessons learned, and ensuring distribution to all stakeholders/plan holders.

Annual Emergency Response Plan Training and Exercise.

Annual Training. The Utility Manager shall conduct staff training for designated personnel on the Emergency Response Plan in preparation for emergencies and major outages each year just before the winter storm season; typically, in September or October. The training shall be designed to overcome problems identified in the evaluations of responses to a major outage or exercise and shall reflect relevant changes to the plan.

Annual Exercise. The Utility Manager shall conduct an exercise annually using the procedures set forth in this emergency plan. If the BVES uses the Emergency Response Plan during the twelve-month period in responding to an event or major outage, the annual exercise is not required for that period. However, the Utility Manager should also evaluate whether or not staff would benefit from the exercise regardless of the fact that the Emergency Response Plan was utilized within the previous 12-month period. For example, if a major change to the Outage Management System is installed since the last Emergency Response Plan activation, it would be appropriate to at a minimum exercise that portion of the plan.

Exercise Notice. The Utility Manager shall provide no less than ten days' notice of the annual exercise to appropriate state and local authorities, including the CPUC, state and regional offices of the OES or its successor, the California Energy Commission, and emergency offices of the counties in which the exercise is to be performed.

Exercise Evaluation. The response to an exercise or major outage shall be evaluated per Section 4.9. The evaluation shall be provided to Regulatory Affairs Manager so that it may be forwarded to the CPUC as part of the report required by GO-166 Standard 11.

Emergency Response Outreach Training. The Utility Manager shall conduct outreach with the county and city emergency response officials and participate as applicable in other emergency exercises designed to address problems on electric distribution facilities or services, including those emergency exercises of the state and regional offices of the OES or its successor, and county emergency offices.

Initial Notification. The Utility Manager shall ensure that the notifications in accordance with the requirements provided in BVES's Electric Utility Emergency Reporting Policy and Procedures are achieved within the required timeframes.

<u>Emergency Response Communications Plan</u>.

Strategy Overview. Achieving unity of effort provides for the most effective and efficient emergency response. This is best attained through the "4 C's" of disaster planning:

Collaboration
Cooperation
Coordination
Communication

The first three hinge upon effective communications. The overall communications strategy is structured so that all stakeholders receive accurate, timely and consistent information, with an overall message for safety of the public, employees and contractors. Communications with local government agencies, customers and other stakeholders are vital to the successful implementation of the EDRP. The plan aims to identify who should be given specific information, when that information should be delivered, and what communication channels shall be used to deliver the information.

During a major outage the Operations Group shall make it a priority to provide the following information to the Public Information Group:

Extent of the outage – using our Outage Management System (OMS) and available field assessment and data, determine how many customers are affected and in which areas
Cause of the outage – provide in broad terms. If unknown, provide status of crews responding to investigate including updating once the power has been restored.
Estimated time of restoration (ETR) – this is the key information customers want to know. If unknown, state so and update as more information becomes available. Don't let ETRs become stale (for example, if a posted ETR is extended, update the posting with a revised ETR).

The Customer Service Supervisor is responsible for updating and executing the BVES communications plan in support of the EDRP. The Utility Manager is responsible for ensuring that accurate information from the Operations Group flows to staff responsible for executing the communications plan.

Additionally, the Customer Service Supervisor shall maintain "call center metrics" that measure customer access to information on customer service calls and web host availability during an emergency or disaster.

Establish Multiple and Effective Communication Channels. Establishing a multilayered communications plan utilizing many separate communications channels is essential to ensuring that the communications plan shall be effective in reaching targeted audiences under uncertain and severe conditions, as would be expected for major outages and disasters and/or following such events. For example, some customers may lose their landline capability in a power outage but still have cell phone service. Plan resiliency, therefore is dependent on having many overlapping layers of communications.

<u>Outbound Communications</u>

BVES website
BVES social media
Online meetings/broadcasts
Interactive Voice Response System
Press releases to local media
Press conference
Phones – landlines, mobile cellular, and satellite lines
Email
- Two-way text messaging
- Door hangers
- Keeping staff who interact with customers informed with latest message
- Advertising
- Community workshops and presentations
- Mail (for example, flyers, newsletters)
- Bill inserts
- County and City communication systems
- Big Bear Chamber of Commerce email blast
- City email blast
- Bear Valley local government, agencies and utilities Public Information Group

<u>Inbound Communications</u>:

Interactive Voice Response System
Call center phone lines
BVES social media
Customer service windows
Bear Valley local government, agencies and utilities Public Information Group
Phones – landlines, mobile cellular, and satellite lines
Email
- Text messaging
- Activate internal PSPS list
- Press inquiries
- iRestore Reports

Internal Communications:

Phones – landlines, mobile cellular, and satellite lines
Email
Text messaging
FaceTime, Skype, Online Meetings, etc.
Intranet – shared drives, internal applications, and SharePoint
Radios – VHF
Direct reports

There are many developing and evolving communications technologies; therefore, it is essential that staff continually evaluate the above lists and modify as applicable. Changes should be evaluated each time the plan is updated.

Besides having multiple communications channels, there are three other elements that are essential to ensuring an effective communications strategy:

Testing and exercising the communications channels frequently so that staff are trained on their usage, target audiences and key stakeholders are familiar with them, and technical issues are resolved prior to an actual emergency. Once testing and exercising of communication channels is complete, adjustments will be made based on lessons learned.
Establishing good business relationships and rapport with target audiences and key stakeholders prior to any emergency.
Maintaining accurate contact information with key stakeholders per Section 3.11 (Key External Contacts List) of this plan.

Conduct Pre-Incident Outreach and Education. BVES has developed a multi-level approach to community education and outreach related to public awareness of outages, emergencies, and emergency preparedness. An important aspect of managing expectations is to conduct education and outreach with customers and key stakeholders well in advance of any emergency. This allows target audiences the opportunity to be ready and provides them the knowledge of what to expect and how to prepare in the event of an emergency such as an extended outage due to a major winter storm or other natural disaster. *A community that is knowledgeable and ready for emergency events will be a force multiplier in emergency response actions*.

City and County Outreach. The Utility Manager shall coordinate with city and county officials in compliance with Public Utilities (P.U.) Code Section 768.6, which requires the following outreach by BVES:

In developing and adopting an emergency and disaster preparedness plan, BVES shall invite appropriate representatives of every city and county within the BVES service area to meet with, and provide consultation to BVES.
BVES shall provide the point of contact designated by the city and county with an

opportunity to comment on draft emergency and disaster preparedness plans.

Every two years, in order to update and improve BVES's emergency and disaster preparedness plan, BVES shall invite appropriate representatives of every city and county within its service area to meet with, and provide consultation to BVES. All recommendations and input will be considered and updated should it be determined to be beneficial for the EDRP. The meeting shall be noticed and shall be conducted in a public setting that allows for the participation of appropriate representatives of counties and cities within the BVES service area. Participating counties and cities shall be provided with the opportunity to provide written and verbal input regarding BVES's emergency and disaster preparedness plan. For purposes of this public meeting, BVES may convene a closed meeting with representatives from every city and county within its service area to discuss sensitive security-related information in BVES's emergency and disaster preparedness plan and to solicit comments.

BVES shall notify the commission of the date, time, and location of the above meeting. BVES shall memorialize the meeting and shall submit its records of the meeting to the commission.

BVES may comply with the meeting requirement that is ordered by the Public Utilities Code by : i) making a presentation regarding its emergency and disaster preparedness plan at a regularly scheduled public meeting of each disaster council created pursuant to Article 10 (commencing with Section 8610) of Chapter 7 of Division 1 of Title 2 of the Government Code within BVES' service area; or ii) at a regularly scheduled public meeting of the governing body of each city located within the service area.

<u>General Public, Customer and Stakeholder Outreach and Education (before an emergency)</u>. Utilizing BVES website, social media, public workshops, meetings with key stakeholders, press releases, advertising, newsletters, bill inserts, two-way text communication, IVR, and other communications channels, the Utility Manager and Customer Service Supervisor shall work to educate, inform and conduct outreach with the general public, customers and stakeholders such as local government and agencies, community groups and other utilities on the following topics:

Customer power outage readiness preparation, including publishing a customer checklist for outages

Backup generators and safety training

Reporting outages

Reporting wire down events and how to handle the situation

Public Safety Power Shutoff policies

Wildfire prevention measures including the vegetation management, covered wire, and distribution system inspection programs

Operational initiatives that support wildfire prevention efforts such as re-closer and circuit patrol policies

Outage restoration strategies used by BVES

Infrastructure projects to improve safety, reliability and mitigate wildfires

Other topics as deemed appropriate by the Utility Manager and/or Energy Resources Manager

In addition to the above outreach, the Utility Manager shall endeavor to periodically brief key elements of the EDRP at Big Bear Valley Mountain Mutual Aid Association ("MMAA") meetings, Big Bear Joint Utility meetings, Big Bear Fire Department and Sheriff's Department leadership.

The Utility Manager and Customer Service Supervisor shall develop and implement a strategy to periodically brief local government and agencies on BVES' emergency response plan. During these interactions, it is important to establish business relationships with local government and its agencies, other key community stakeholders, and other utilities so that during emergencies the BVES Leadership Team may seamlessly engage these groups. The Utility Manager and Customer Service Supervisor shall develop a contact list of the key staff at local government and agencies to notify during emergency events. The contact list should include preferred and back-up means of contact (for example, mobile phone number, email, office phone, etc.). The contact list shall be verified, corrected and updated as necessary at least every six months by the Administrative Support Associate.

The list of local government and agencies and key stakeholders shall include at a minimum the following organizations:

Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
State officials (normally CPUC Energy Division and Safety Enforcement Division)

- San Bernardino County Office of Emergency Services (County OES)
- Big Bear Fire Department
- California Department of Forestry and Fire Protection (CAL FIRE)
- U.S. Forest Service
- San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
- California Highway Patrol (CHP) Arrowhead Area
- California Department of Transportation (Caltrans)
- Big Bear Area Regional Wastewater Agency (BBARWA)
- Big Bear City Community Services District (CSD)
- Big Bear Lake Water Department (DWP)
- Big Bear Municipal Water District (MWD)
- Southwest Gas Corporation
- Bear Valley Community Hospital
- Bear Valley Unified School District
- Big Bear Chamber of Commerce
- Big Bear Airport District
- Big Bear Mountain Resort
- Local communication companies (Spectrum and various cell providers)

Provide Outreach in Prevalent Languages. United States Census data shows that the top three primary languages used in California are English, Spanish and Chinese (including Cantonese, Mandarin and other Chinese languages). BVES shall communicate its emergency preparedness outreach and response in English, Spanish, Chinese (including Cantonese, Mandarin and other Chinese languages), Tagalog, and Vietnamese. Additionally, BVES has included two indigenous languages (Zapateco and Mixteco) as part of its wildfire mitigation communications.

Provide Emergency Incident Communications. Utilizing the multiple communications channels discussed earlier, the Public Information Group and Emergency Response Leadership Team shall engage and educate the general public, local government and its agencies, and other key stakeholders to provide notification of outages and emergencies, estimated time to restore service, cause of outage (if known), and periodic updates as appropriate. The following sections provide detail on how these communications shall be conducted.

Set Expectations and Develop Trust. When an emergency occurs, BVES shall communicate with the general public, customers, local government and its agencies, and key stakeholders as soon as possible to set expectations and address emergency issues. When business operations or households are disrupted by power outages, customers expect to know how long they shall be impacted. Thus, estimated restoration times (ETRs) shall be developed, monitored, adjusted and communicated. Establishing ETRs is a key function of the Operations Group. Regulators and local government officials shall be notified regarding the impact to communities per GO 166 Standard 6. Customer Service Supervisor shall:

Work with BVES's public relations contractor subject matter experts (SMEs) to develop consistent and accurate BVES messaging to customers and stakeholders.
Employ consistent and frequent multi-channel communications to disseminate information that leverage and reinforce one another.
Brief employees; especially field staff and customer service representatives, on the latest information so that their interactions with the public are consistent with the messaging.
Coordinate closely with the Operations Group to provide customers and stakeholders system updates including best known restoration times.
Ensure that all communications are accurate and always factually correct. If incorrect information is inadvertently issued, then it is important that a correction be issued as soon as known and that the error be acknowledged. If information is not certain, then avoid reporting it or qualify it as appropriate. For example, "BVES has received reports of a downed tree on its power lines on Moonridge Road; field crews have been dispatched to validate the report and assess any damage that may have resulted."
Strive to be transparent; it is absolutely critical to our credibility and to ensuring that the public, customers and stakeholders have the upmost confidence in our ability to perform our essential public service – providing safe, reliable, and high quality electric service.

Per GO 166 Standard 6, BVES shall provide an initial notification within one hour of the identification of a major outage or other newsworthy event. BVES shall also notify the Commission and San Bernardino County Warning Center at the Office of Emergency Services of the location, possible cause and expected duration of the outage. The Warning Center at the OES is expected to notify other state and local agencies of the outage. Subsequent contacts between state and local agencies and BVES shall be conducted between personnel identified in advance, as set forth in Standard 4.B (Communications Strategy with Government). From time to time the Commission staff may issue instructions or guidelines regarding reporting.

Notify and Engage Key Stakeholders. Keeping local government and agency officials as well as other key stakeholders informed of emergencies is critical to their ability to operate and support their missions. It is far more advantageous for these officials and key stakeholders to receive information directly from BVES Leadership in a timely manner rather than via the media.

Utilizing the contact list developed during pre-incident engagement, BVES Leadership should notify local government and agencies and other key stakeholders of emergencies and provide them updates as appropriate. Some of this notification may be achieved by sending to the local "Public Information Officer" developed through MMAA group email notifications and status updates.

Notify Customers and General Public. The Customer Service Supervisor shall develop pre-planned statements with fill-in-the-blank sections for potential outage and emergency events. These pre-planned statements shall be used as deemed appropriate by the Customer Service Supervisor to update customers and the general public as soon as feasible via the following means:

News releases (newspaper, online news outlets, radio, etc.)
Website updates
Social media updates
IVR messages
Two-way text communication
Email notifications to customers
Other public and customer engagement media (for example, City of Big Bear Lake's email blast)

Specific guidance on developing press releases and statements and engaging the media is provided in the next section. Customer Service Supervisor shall develop pre-planned statements for IVR and text message use. IVR and text messages should be short – about one sentence – and may refer the customer to additional information sources such as our website or social media. For example, "BVES crews are responding to outages on the North Shore and the estimated time to restore power is 2 pm – additional information is available at www.bves.com."

Media Engagement Procedures. By proactively engaging the media, BVES is able to reach a wide audience in its service area and establish the opportunity to convey the correct narrative and information to the general public. When engaging the media, it should be understood that in general the media are:

Professionals at what they do – they are normally just doing their job and are experts at interviews.
Often, they are deadline driven.

Therefore, when working with the media as a BVES spokesperson, staff must be prepared and properly authorized. Any employee speaking to media whether "on the record" or "off the record" automatically becomes a spokesperson for the BVES willingly or unwillingly.

Authorized Media Engagement. The Public Information Group is the authorized group to interact with the media and they shall lead all media engagement efforts. They shall work closely with the Operations Group to ensure they have accurate information, develop press releases with the assistance of the BVES's public relations firm, coordinate releases with other organizations such as local government and agencies, and clear press releases with the President prior to releasing them.

It should be recognized that media representatives could reach out to BVES employees at any time; especially, BVES employees (and their contractors) out in the field. Therefore, Managers and Supervisors must ensure their employees are periodically updated with the status of the emergency response and train their employees to respond to direct media reporter inquiries as follows:

At all times act politely and professionally.
Write down the reporter's name, organization, and phone number.
Write down any questions the reporter may have.
It is acceptable for field crews and staff to respond to questions directly pertaining to the conditions or work being performed by them. For example, it is acceptable for field crews to describe how the weather is impacting their immediate restoration work out in the field. However, any larger questions, such as estimated time of restoration, other reported outages, availability of resources (manpower and materials), restoration strategy should be written down and the reporter informed that BVES shall get back to them.
In all cases, the employee approached by the media must inform their Supervisor or Manager as soon as possible of the inquiry and pass along the contact information, questions asked, and any answers provided. This information must be immediately conveyed to the Public Information Group.

The Public Information Group should follow up as soon as feasible with the reporter even if the employee responded to the questions.

Press Release Content. The Public Information Group shall develop press releases from pre-planned press release templates as feasible. These are especially useful in the initial stages of an emergency where information is still sparse. They allow for rapid dissemination of initial information of the emergency scope. As the Operations Group obtains more accurate information from Field Crews, the press releases should be updated accordingly. Additionally, they shall consult with BVES's public relations contractor to develop press releases and an engagement strategy tailored to the specific emergency.

Press releases should make the best attempt at addressing the "who, where, why, what, when, and how" to the emergency event. However, do not delay issuing a press release to obtain all of this information. The information can be relayed in press release updates. Ideally, in a large outage, the following information should be released as it is known:

(Who/where) Location of the outage and who is affected – use geographic locations such as areas or streets (for example, “Moonridge Area”, “from the Village to the Dam on the South shore of the lake”, “from Pine Knot Ave to Paine Rd on the South Shore of Big Bear Lake”, etc.). Avoid using circuit and/or substation names to describe the location, since these names have little meaning to the public.

(When) Time outage started and estimated time of restoration (ETR).

(Who) Number of customers without power. Provide the best estimate available and update as it is changed.

> **(Why/what)** Cause of the outage and location of damage/problem. Use simple descriptions that a non-utility audience would understand (for example, “car hit a ground mounted transformer causing sufficient damage to take it out of service,” “an 80-foot tree fell from across the street on Pine Knot Ave onto a major overhead power line,” “loss of power supply from Goldhill due to fault on Southern California Edison equipment,” etc.).

(When) Whether or not Field Crews are conducting repairs to restore power. If crews are not on site, provide an estimated time of arrival if available.

(How) Actions being taken to restore power (starting BVPP, conducting field switching to alternate sources of power, conducting repairs to damaged equipment, etc.).

Pictures of the damage and field crews conducting repairs are always very useful.

Press Release Protocols. The Public Information Group under the leadership of Customer Program Specialist shall be responsible for drafting and issuing press releases from the BVES to the media. Press releases shall be drafted, approved, and released per the protocol shown in Figure 5-1, Press Release Protocol.

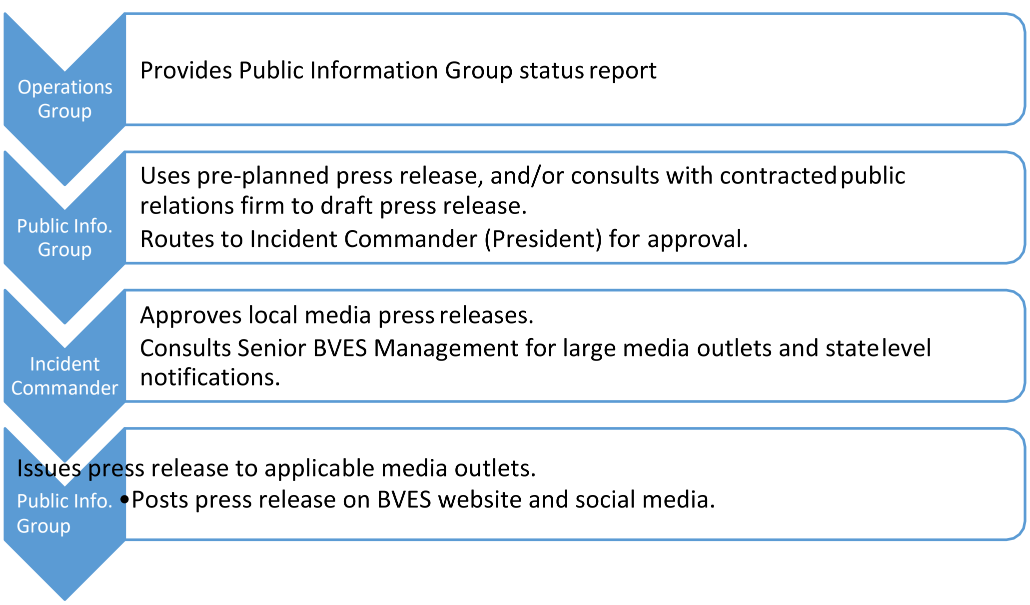

Figure 5-1: Press Release Protocol

Post Emergency Event Close-out Statement. Once the Emergency Response is determined to be no longer necessary, Customer Service Supervisor shall prepare a summary press release and statement providing customers a brief summary of the emergency event and provide any post incident support instructions such as:

Information on whom to contact at BVES to reconnect service for customers whose weather head or other equipment was damaged preventing immediate service restoration.
Information on obtaining post incident customer support per Section 6 of this plan.

Reports to the Commission. The Utility Manager shall ensure required reports to the Commission and its Divisions are made in a timely and complete manner. These reports include:

Notify California Public Utilities Commission (CPUC) and Warning Center at the Office of Emergency Services San Bernardino within one hour of an outage if the outage meets the major outage criteria of GO-166.

Notify President Safety Enforcement Division (SED), CPUC within twelve hours of the power being shut-off per ESRB-8.
Provide a report (written) to President of SED no later than 10 business days after the shut- off event ends per ESRB-8.

Customer Support in Emergencies. In the event the Governor of California declares a state of emergency because a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service, BVES shall implement certain customer service actions as described below. This section provides an overview of the protocols for compliance with requirements adopted by the CPUC regarding activities to support customers. The protocols span customer billing, support for low income, life support, Access and Functional Needs (AFN) customers, and other forms of customer support.

Support for Low Income, Life Support and AFN customers. The Customer Care Team shall freeze low income, life support, and AFN customer accounts and stop all California Alternative Rates for Energy (CARE) High-Usage tracking. The Supervisor shall work with implementation contractors and emergency assistance programs to update affected customers on eligibility requirements and enroll them in assistance programs.

Billing Adjustments. The Customer Care Team shall freeze accounts and stop billing during the disaster event to ensure bills are not estimated or generated for affected customers. Billing shall resume once the case is closed by the Customer Care & Billing (CC&B) technical team, upon notice from the Supervisor.

Deposit Waivers. The Customer Care Team shall add a designated customer contact for all affected customers. The contact shall reside within CC&B for up to one year from the date the emergency ends. This shall allow BVES to easily track the customer's account, so when service is re-established, the utility shall know to waive any associated fees and to expedite customer re-connection.

Extended Payment Plans. The Customer Care Team shall freeze all payments on affected customers' account to avoid affecting their credit. All affected customers shall be notified that an extended payment plan option is available for any past due payments.

Suspension of Disconnection and Nonpayment Fees. The Customer Care Team shall freeze affected customer accounts, so disconnections and nonpayment fees are not generated during the disaster event. Once the emergency ends, the Supervisor and/or Specialist shall contact the CC&B Team to "close" all affected customer cases. This shall automatically transition the customer's account back to the normal state. BVES shall simultaneously begin assisting with service restoration and deposit waivers.

Repair Processing and Time. During emergencies, BVES shall set up specialized repair teams to expedite repair processing. If additional support is needed, BVES shall leverage mutual aid programs with other emergency response resources and shall work with electrical contractors to ensure timely service restoration. Exact timing shall be dependent on the nature of the situation.

Access to Utility Representatives. The BVES Engineering Technician shall arrange for connections and facilitate expedited services. Leveraging its IVR system, BVES shall be able to handle thousands of phone calls simultaneously and divert customers to the appropriate utility representative.

Access to Outage Reporting and Emergency Communications. During emergencies, BVES shall invoke its emergency communications plan per the EDRP to attempt to reach as many customers as feasible with outage, restoration and recovery information via multilayered communications channels and multiple languages per Section 5.4 of the EDRP.

APPENDIX D. BVES 2021 Q4 QDR

D.1 QDR Table 1

Utility	Service, Inc.	**Notes:**
Table No.	1	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	4/14/2022	

Note: These columns are placeholders for future QR submissions.

Table 1: Recent performance on progress metrics

Metric type	#	Progress metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Grid condition findings from inspection - Distribution lines in HFTD	1.a.	Number of circuit miles inspected from patrol inspections in HFTD - Distribution lines	210.81	210.81	210.81	210.81	210.81	85.02	0.66	78.5	70.83	84.18	0.66	277.44	97.83					# circuit miles	
	1.b.	Number of circuit miles inspected from detailed inspections in HFTD - Distribution lines	NA	NA	NA	NA	118.61	36.92	0	8.91	0	0	0	52.06	2.84					# circuit miles	2019 values account for months June - December 2019 to align with prior record-keeping practices of June - May for WMP metric tracking periods.
	1.c.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Distribution lines	NA	NA	NA	NA	12	0	0	264.98	233.51	0	0	289.56	0					# circuit miles	2019 values account for months June - December 2019 to align with prior record-keeping practices of June - May for WMP metric tracking periods.
	1.d.	Level 1 findings in HFTD for patrol inspections - Distribution lines	NA	NA	0	2	0	3	1	0	0	0	0	0	0					# findings	
	1.e.	Level 1 findings in HFTD for detailed inspections - Distribution lines	NA	NA	0	4	3	2	0	2	0	0	0	0	0					# findings	
	1.f.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	2	0	0	0	0	0	0	0	0	0					# findings	
	1.g.	Level 2 findings in HFTD for patrol inspections - Distribution lines	NA	NA	0	127	14	40	5	0	0	0	0	2	1					# findings	
	1.h.	Level 2 findings in HFTD for detailed inspections - Distribution lines	NA	NA	0	307	248	14	1	38	0	1	0	3	0					# findings	
	1.i.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	127	14	0	0	0	39	0	0	12	0					# findings	
	1.j.	Level 3 findings in HFTD for patrol inspections - Distribution lines	NA	NA	668	271	329	9	4	0	0	1	1	0	3					# findings	
	1.k.	Level 3 findings in HFTD for detailed inspections - Distribution lines	NA	NA	0	61	134	328	0	289	0	45	0	93	0					# findings	
	1.l.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	271	329	0	57	0	246	0	0	94	0					# findings	
1. Grid condition findings from inspection - Distribution lines total	1.a.ii.	Number of total circuit miles inspected from patrol inspections - Distribution lines	210.81	210.81	210.81	210.81	210.81	85.02	0.66	78.5	70.83	84.18	0.66	277.44	97.83					# circuit miles	
	1.b.ii.	Number of total circuit miles inspected from detailed inspections - Distribution lines	NA	NA	NA	NA	118.61	36.92	0	8.91	0	0	0	52.06	2.84					# circuit miles	
	1.c.ii.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	NA	NA	12	0	0	264.98	233.51	0	0	289.56	0					# circuit miles	
	1.d.ii.	Level 1 findings for patrol inspections - Distribution lines	NA	NA	0	2	0	3	1	0	0	0	0	0	0					# findings	
	1.e.ii.	Level 1 findings for detailed inspections - Distribution lines	NA	NA	0	4	3	2	0	2	0	0	0	0	0					# findings	
	1.f.ii.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	2	0	0	0	0	0	0	0	0	0					# findings	
	1.g.ii.	Level 2 findings for patrol inspections - Distribution lines	NA	NA	0	127	14	40	5	0	0	0	0	2	1					# findings	
	1.h.ii.	Level 2 findings for detailed inspections - Distribution lines	NA	NA	0	307	248	14	1	38	0	1	0	3	0					# findings	
	1.i.ii.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	127	14	0	0	0	39	0	0	12	0					# findings	
	1.j.ii.	Level 3 findings for patrol inspections - Distribution lines	NA	NA	668	271	329	9	4	0	0	1	1	0	3					# findings	
	1.k.ii.	Level 3 findings for detailed inspections - Distribution lines	NA	NA	0	61	134	328	0	289	0	45	0	93	0					# findings	
	1.l.ii.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	0	271	329	0	57	0	246	0	0	94	0					# findings	
1. Grid condition findings from inspection - Transmission lines in HFTD	1.a.iii.	Number of circuit miles inspected from patrol inspections in HFTD - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.b.iii.	Number of circuit miles inspected from detailed inspections in HFTD - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.c.iii.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.d.iii.	Level 1 findings in HFTD for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.e.iii.	Level 1 findings in HFTD for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.f.iii.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.g.iii.	Level 2 findings in HFTD for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.h.iii.	Level 2 findings in HFTD for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.i.iii.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.j.iii.	Level 3 findings in HFTD for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.k.iii.	Level 3 findings in HFTD for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.l.iii.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
1. Grid condition findings from inspection - Transmission lines total	1.a.iv.	Number of total circuit miles inspected from patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.b.iv.	Number of total circuit miles inspected from detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.c.iv.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# circuit miles	BVES does not have any equipment 65kV or above
	1.d.iv.	Level 1 findings for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.e.iv.	Level 1 findings for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.f.iv.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.g.iv.	Level 2 findings for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.h.iv.	Level 2 findings for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.i.iv.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.j.iv.	Level 3 findings for patrol inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.k.iv.	Level 3 findings for detailed inspections - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
	1.l.iv.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# findings	BVES does not have any equipment 65kV or above
2. Vegetation clearance findings from inspection - total	2.a.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition - total	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41					# of spans inspected with noncompliant clearance based on applicable rules and regulations at the time of inspection	No data available prior to 2020
	2.a.ii	Number of spans insepcted for vegetation compliance - total	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029					# of spans inspected for vegetation compliance	No data available prior to 2020
2. Vegetation clearance findings from inspection - in HFTD	2.b.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition in HFTD	NA	NA	NA	NA	NA	486	157	395	285	239	133	107	41					# of spans inspected with noncompliant clearance based on applicable rules and regulations at the time of inspection	No data available prior to 2020
	2.b.ii	Number of spans insepcted for vegetation compliance in HFTD	NA	NA	NA	NA	NA	863	328	659	648	675	567	5221	4029					# of spans inspected for vegetation compliance	No data available prior to 2020
3. Community outreach metrics	3.a.	# Customers in an evacuation zone for utility-ignited wildfire	0	0	0	0	0	0	0	0	0	0	0	0	0					# customers (if customer was in an evacuation zone for multiple wildfires, count the customer for each relevant wildfire)	
	3.b.	# Customers notified of evacuation orders	0	0	0	0	0	0	0	0	0	0	0	0	0					# customers (count customer multiple times for each unique wildfire of which they were notified)	
	3.c.	% of customers notified of evacuation in evacuation zone of a utility-ignited wildfire	0	0	0	0	0	0	0	0	0	0	0	0	0					Percentage of customers notified of evacuation	

D.2 QDR Table 2

Utility	Service, Inc.	**Notes:**
Table No.	2	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	4/14/2022	HWW = High wind warning
		RFW = Red flag warning

Table 2: Recent performance on outcome metrics

Note: These columns are placeholders for future QR submissions.

Metric type	#	Outcome metric name	Wind Warning Status	HFTD Tier	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Risk Events	1.a.	Number of all events with probability of ignition, including wires down,	All	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA				Number per year	BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	2	33	85	83	31	25	4	3	6	4	8	5	10	4	3					BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	2	NA	NA	NA	1	1	0	0	1	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	2	NA	NA	NA	1	6	0	0	0	0	2	0	0	0	2					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	2	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	2	NA	NA	NA	NA	6	0	0	0	0	2	0	0	0	2					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0					BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						BVES does not have Non-HFTD or Tier 1 designations
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						BVES does not have Non-HFTD or Tier 1 designations

1. Risk Events	1.b.	Number of wires down	All	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of wires down per year	BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW & RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW & not RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	All	2	7	17	4	3	3	2	1	0	0	1	1	2	1		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of wires down	RFW	2	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	HWW	2	NA	NA	NA	0	2	0	0	0	0	0	0	0	0		
		Number of wires down	HWW & RFW	2	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	HWW & not RFW	2	NA	NA	NA	0	2	0	0	0	0	0	0	0	0		
		Number of wires down	All	3	0	0	0	0	0	0	0	0	0	0	0	0	0		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of wires down	RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	HWW	3	0	0	0	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	HWW & RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	HWW & not RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0		
		Number of wires down	All	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW & RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of wires down	HWW & not RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
1. Risk Events	1.c.	Number of outage events not caused by contact with vegetation	All	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of outage events per year	BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW & RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW & not RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	All	2	NA	47	79	25	21	2	7	22	21	13	0	11	16		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of outage events not caused by contact with vegetation	RFW	2	NA	NA	NA	1	2	0	0	1	2	0	0	0	0		
		Number of outage events not caused by contact with vegetation	HWW	2	NA	NA	NA	0	3	0	0	0	1	4	0	0	1		
		Number of outage events not caused by contact with vegetation	HWW & RFW	2	NA	NA	NA	0	0	0	0	0	1	0	0	0	0		
		Number of outage events not caused by contact with vegetation	HWW & not RFW	2	NA	NA	NA	0	3	0	0	0	0	4	0	0	1		
		Number of outage events not caused by contact with vegetation	All	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of outage events not caused by contact with vegetation	RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events not caused by contact with vegetation	HWW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events not caused by contact with vegetation	HWW & RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events not caused by contact with vegetation	HWW & not RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events not caused by contact with vegetation	All	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW & RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events not caused by contact with vegetation	HWW & not RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
1. Risk Events	1.d.	Number of outage events caused by contact with vegetation	All	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of outage events per year	BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW & RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW & not RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	All	2	NA	28	16	9	5	3	1	0	1	0	0	1	5		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of outage events caused by contact with vegetation	RFW	2	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW	2	NA	NA	NA	0	4	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW & RFW	2	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW & not RFW	2	NA	NA	NA	0	4	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	All	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of outage events caused by contact with vegetation	RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW & RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	HWW & not RFW	3	NA	NA	NA	0	0	0	0	0	0	0	0	0	0		
		Number of outage events caused by contact with vegetation	All	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW & RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of outage events caused by contact with vegetation	HWW & not RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
2. Utility inspection findings - Distribution	2.a.	Number of Level 1 findings (distribution)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of Level 1 findings (distribution)	N/A	2	NA	NA	0	8	3	5	1	2	0	0	0	0	0		
		Number of Level 1 findings (distribution)	N/A	3	NA	NA	0	0	0	0	0	0	0	0	0	0	0		
		Number of Level 1 findings (distribution)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
	2.b.	Number of Level 2 findings (distribution)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of Level 2 findings (distribution)	N/A	2	NA	NA	0	561	276	54	6	38	39	1	4	17	1		
		Number of Level 2 findings (distribution)	N/A	3	NA	NA	0	0	0	0	0	0	0	0	0	0	0		
		Number of Level 2 findings (distribution)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
	2.c.	Number of Level 3 findings (distribution)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of Level 3 findings (distribution)	N/A	2	NA	NA	668	603	792	337	61	289	246	46	1	187	3		
		Number of Level 3 findings (distribution)	N/A	3	NA	NA	0	0	0	0	0	0	0	0	0	0	0		
		Number of Level 3 findings (distribution)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
	2.d.	Number of distribution circuit miles inspected	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of distribution circuit miles inspected	N/A	2	NA	NA	210	210	210	118	93	210	210	84	0.66	619.06	100.67		
		Number of distribution circuit miles inspected	N/A	3	NA	NA	1.27	1.27	1.27	0	0	1	1	0	0	1.52	0		
		Number of distribution circuit miles inspected	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
2. Utility inspection findings - Transmission	2.a.ii	Number of Level 1 findings (transmission)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have Non-HFTD or Tier 1 designations
		Number of Level 1 findings (transmission)	N/A	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 1 findings (transmission)	N/A	3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 1 findings (transmission)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
	2.b.ii	Number of Level 2 findings (transmission)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 2 findings (transmission)	N/A	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 2 findings (transmission)	N/A	3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 2 findings (transmission)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
	2.c.ii	Number of Level 3 findings (transmission)	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 3 findings (transmission)	N/A	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 3 findings (transmission)	N/A	3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of Level 3 findings (transmission)	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
	2.d.ii	Number of transmission circuit miles inspected	N/A	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of transmission circuit miles inspected	N/A	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of transmission circuit miles inspected	N/A	3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
		Number of transmission circuit miles inspected	N/A	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES does not have any equipment 65kV or above
	3.a.	Fatalities due to utility-related ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0		
	3.b.	Injuries due to utility-related igntions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0		

4. Value of assets destroyed by utility-related ignitions, listed by asset type	4.a.	Value of assets destroyed by utility-related ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
5. Structures damaged or destroyed by utility-related ignitions	5.a.	Number of structures destroyed by utility-related ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
	5.b.	Critical infrastructure damaged/destroyed by utility-rleated ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
6. Acreage burned by utility-related ignitions	6.a.	Acreage burned by utility-rleated ignitions	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
7. Number of utility-related ignitions	7.a.	Number of ignitions (total) according to existing ignition data reporting requirement	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
	7.b.	Number of ignitions	All	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW & RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW & not RFW	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	All	2	0	0	0	0	0	0	0	0	0	0	0	0	0	BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of ignitions	RFW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW & RFW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW & not RFW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	All	3	0	0	0	0	0	0	0	0	0	0	0	0	0	BVES uses this entry for "not known" or N/A as the option is not provided.
		Number of ignitions	RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW & RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	HWW & not RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	
		Number of ignitions	All	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW & RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
		Number of ignitions	HWW & not RFW	Non- HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	BVES does not have Non-HFTD or Tier 1 designations
8. Fatalities resulting from utility wildfire mitigation initiatives	8.a.	Fatalities due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted for in the 2020 WMP proposed WMP spend	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	
9. OSHA-reportable injuries from utility wildfire mitigation initiatives	9.a.	OSHA-reportable injuries due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted for in the 2020 WMP proposed WMP spend	N/A	N/A	0	0	0	1	0	0	0	0	0	0	0	0	0	

D.3 QDR Table 3

Utility	Bear Valley Electric Service, Inc.
Table No.	3
Date Modified	4/14/2022

Table 3: List and description of additional metrics

Note: These columns are placeholders for future QR submissions.

Metric	Definition	Purpose	Assumptions made to connect metric to purpose	Third-party validation (if any	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
Number of poles assessed	Count of poles assessed	Identify # of inspected poles to reduce the number of pole failures & possibility of fire	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	924	1588	10	12	51	118	279	73	48	157					Count of poles assessed	Metric not recorded prior to 2018
Number of poles that failed assessment (wind loading, age, deterioraton, unfixable GO-95 violation)	Count of poles that fail assessment	Identify proper pole replacement periodicty, lifespan, etc. and reduce possibility of fire	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	655	393	9	11	37	50	98	41	11	129					Count of poles that fail assessment	Metric not recorded prior to 2018
Number of poles replaced as a result of failed assessments	Count of poles replaced	Demonstrates progress of fire resilience efforts	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	210	305	44	87	60	45	48	62	48	58					Count of poles replaced	Metric not recorded prior to 2018
Number of poles remediated as a result of failed assessments	Count of poles remediated as a result of failed assessment	Demonstrates progress of fire resilience efforts	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	40	66	0	7	0	0	1	3	2	1					Count of poles remediated as a result of failed assessment	Metric not recorded prior to 2018
Number of Tree Attachments Removed	Count of tree attachments removed	Demonstrates progress toward goal of zero tree attachment and reduce possibility of fire	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	230	43	59	114	24	17	0	4	0	70					Count of tree attachments removed	Metric not recorded prior to 2018
Number of new poles installed as a result of Tree Attachments Removed	Count of poles installed to replace wiring attachment from prior tree attachment	Demonstrates progress in reducing direct vegetation contact risk and installing more resilient poles in place of the prior attachment.	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	9	57	89	22	6	0	4	0	36					Count of poles installed to replace wiring attachment from prior tree attachment	Metric not recorded prior to 2019. Year 2019 only includes pole number from June 2019 - December 2019 due to prior tracking cycle of June through May as opposed to calendar or fiscal year cycle.
Length of Covered Bare Wire (Circuit Miles)	Miles of covered bare wire	Demonstrates progress in covering bare wire	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	0.52	0	1.814962	0.52	5.5	0	5.15	3.74	3.41					Miles of covered bare wire	Metric not recorded prior to 2019 WMP No data for May 2020
Percent of 34.5 kV System that is Overhead Bare Wire	Percent of 34.5 kV System that is Overhead Bare Wire	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0.97	0.97	0.96	0.929	0.929	0.83	0.83	0.722	0.71	0.669					Percent of 34.5 kV System that is Overhead Bare Wire	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.
Percent of 34.5 kV System that is Underground	Percent of 34.5 kV System that is underground	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03					Percent of 34.5 kV System that is underground	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.

Percent of 34.5 kV System that is Covered Wire	Percent of 34.5 kV System that is underground	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0	0	0.01	0.04	0.04	0.139	0.139	0.198	0.26	0.301	Percent of 34.5 kV System that is underground	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.
Percent of 4 kV System that is Overhead Bare Wire	Percent of 34.5 kV System that is overhead	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0.773	0.773	0.773	0.772	0.772	0.759	0.759	0.744	0.736	0.722	Percent of 34.5 kV System that is overhead	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.
Percent of 4 kV System that is Underground	Percent of 4 kV System that is underground	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0.227	0.227	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	Percent of 4 kV System that is underground	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.
Percent of 4 kV System that is Covered Wire	Percent of 34.5 kV System that is underground	Inventory	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	0	0	0.001	0.002	0.002	0.015	0.015	0.029	0.038	0.052	Percent of 34.5 kV System that is underground	Metric not recorded prior to 2018 Metric reported total percentage at the end of the quarter.
Number of Tree Attachments Remaining in System	Count of tree attachments	Demonstrates progress toward goal of zero tree attachment and reduce possibility of fire	Assess overall system hardening	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	977	934	875	761	737	720	720	716	716	646	Count of tree attachments	Metric not recorded prior to 2018 Metric reported total number at the end of the quarter.
Number of Trees Trimmed	Count of trees trimmed as part of veg mgmt work	Inventory and identify trends	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	5526	6671	866	761	1201	1708	2330	1980	1688	1841	Count of trees trimmed as part of veg mgmt work	Metric not recorded prior to 2019 WMP
Number of Trees Removed	Count of trees removed as part of veg mgmt work	Inventory and identify trends	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	80	123	16	34	35	43	19	36	85	17	Count of trees removed as part of veg mgmt work	Metric not recorded prior to 2019 WMP
Circuit Miles Trimmed	Number of Circuit Miles with VM trimming	Account for circuit miles that receive tree trimming activities per quarter	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Number of Circuit Miles with VM trimming	New metric being recorded as of Q1 2022
VM QCs	Number of VM QCs performed	Include metrics for the number of quality checks performed on vegtation management activities	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Number of VM QCs performed	New metric being recorded as of Q1 2022
Number of Substations Inspected	Number of Substations Inspected	Accounting record for number of substations inspected quarterly	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Number of Substations Inspected	New metric being recorded as of Q1 2022

Number of Poles Intrusively Inspected	Number of Poles Intrusively Inspected	Inventory and identify performance trends	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	994	927	1013	155	48	0	0	0	0	0	0	876	0	Number of Poles Intrusively Inspected	
Number of Poles Failing Instrusive Inspection	Number of Poles Failing Intrusively Inspection	Inventory and identify trends	Determine if plan is on schedule	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	8	7	4	4	3	0	0	0	0	0	0	28	0	Number of Poles Failing Intrusively Inspection	
Number of Customer Service Calls about Tree Trimming	Number of Customer Service Calls about Tree Trimming	Inventory and identify trends	Monitor changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	Number of Customer Service Calls about Tree Trimming	Metric not recorded prior to 2019 WMP
Number of Customer Engagements in Community Outreach for PSPS and WMP	Count of Engagements	Record of outreach performed each quarter related to WMP activities or PSPS preparedness	Monitor customer and community outreach activities	No third-party validation necessary	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Number of outreach performed	New metric being recorded as of Q1 2022
SAIDI due to PSPS	SAIDI Reliability Performance impacts due to PSPS	Identify impacts to SAIDI performance from PSPS events	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	SAIDI Reliability Performance impacts due to PSPS	BVES has not initiated any PSPS activation to date.
Number of NFDRS "Very Dry" and "Dry" Days	Count of NFDRS "very dry" and "dry" days	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	150	21	57	92	86	34	86	92	65	Count of NFDRS "very dry" and "dry" days	Metric not recorded prior to 2019 WMP. BVES has missing monthly data for Feb. - June 2020
Number of PSPS Events	Count of PSPS events	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	Count of PSPS events	Metric not recorded prior to 2019 WMP
Maximum recorded sustained winds Recorded	Highest recorded sutained wind speed recorded	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	41	25	22	22	30	37	22	30	33	Highest recorded sutained wind speed recorded	Metric not recorded prior to 2019 WMP BVES does not readily have Q2 2020 data available for this filing.
Maximum recorded wind gusts Recorded	Highest recorded sutained wind gust recorded	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Contracted 3rd party analysts or academic researchers could review open as well as closed work orders, BVES GIS databases, staff interviews, as well as spot-checking select items for confirmation of status.	NA	NA	NA	NA	53	43	43	35	45	50	37	44	55	Highest recorded sutained wind gust recorded	Metric not recorded prior to 2019 WMP BVES does not readily have Q2 2020 data available for this filing.
Frequency of sustained high winds (number of days sustained wind > 50 mph)	Count of sustained high wind days recorded	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Data obtained from BVES owned weather stations	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	Count of sustained high wind days recorded	Metric not recorded prior to 2019 WMP BVES does not readily have Q2 2020 data available for this filing.
Frequency of high wind gusts (number of days wind gusts > 50 mph) recorded	Count of days with high wind gusts recorded	Inventory and identify trends	Monitor the need for PSPS events over time as an indicator of changing climatic and weather patterns	Data obtained from BVES owned weather stations	NA	NA	NA	NA	1	0	0	0	0	0	0	0	1	Count of days with high wind gusts recorded	Metric not recorded prior to 2019 WMP BVES does not readily have Q2 2020 data available for this filing.

D.4 QDR Table 4

Utility	Service, Inc.
Table No.	4
Date Modified	4/14/2022

Note: These columns are placeholders for future QR submissions.

Table 4: Fatalities due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Fatalities - Full-time Employee	1.a.	Fatalities due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.b.	Fatalities due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.c.	Fatalities due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.d.	Fatalities due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.e.	Fatalities due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
2. Fatalities - Contractor	2.a.	Fatalities due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.b.	Fatalities due to vegetation management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.c.	Fatalities due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.d.	Fatalities due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.e.	Fatalities due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
3. Fatalities - Member of public	3.a.	Fatalities due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.b.	Fatalities due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.c.	Fatalities due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.d.	Fatalities due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.e.	Fatalities due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	

D.5 QDR Table 5

Utility	Service, Inc.
Table No.	5
Date Modified	4/14/2022

Note: These columns are placeholders for future QR submissions.

Table 5: OSHA-reportable injuries due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. OSHA injuries - Full-time Employee	1.a.	OSHA injuries due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.b.	OSHA injuries due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.c.	OSHA injuries due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.d.	OSHA injuries due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.e.	OSHA injuries due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
2. OSHA injuries - Contractor	2.a.	OSHA injuries due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.b.	OSHA injuries due to vegetation management - Contractor	0	0	0	1	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	On July 19, 2018, a line worker and the owner of Teele Tree Services made contact with a high voltage power line and sustained non-fatal injuries. The injury did not require reporting under CalOSHA guidelines but BVES chose to report the incident.
	2.c.	OSHA injuries due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.d.	OSHA injuries due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.e.	OSHA injuries due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
3. OSHA injuries - Member of public	3.a.	OSHA injuries due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.b.	OSHA injuries due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.c.	OSHA injuries due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.d.	OSHA injuries due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.e.	OSHA injuries due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	

D.6 QDR Table 6

Utility	Service, Inc.
Table No.	6
Date Modified	4/14/2022

Note: These columns are placeholders for future QR submissions.

Table 6: Weather patterns

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Red Flag Warning Overhead circuit mile Days	1.a.	Red Flag Warning Overhead circuit mile days - entire utility territory	615.1953	2987.82	3312.817	2231.955	1335.6297	0	0	807.747	1668.219	0	0	0	790.875					Sum of overhead circuit miles of utility grid subject to Red Flag Warning each day within a given time period, calculated as the number of overhead circuit miles that were under an RFW multiplied by the number of days those circuit miles were under said RFW. For example, if 100 overhead circuit miles were under an RFW for 1 day, and 10 of those miles were under RFW for an additional day, then the total RFW OH circuit mile days would be 110.	The utility's weather consultant collects and reports data using the NFDRS and RFW systems for the utility's entire service territory as opposed to on a circuit-by-circuit basis; when a Red Flag Warning is issued for the San Bernardino Mountains, - including Big Bear Valley, which encompasses the entirey of BVES' service territory - the Warning applies to 100% of BVES' service territory, which is just 32 square miles.
	1.b.	Red Flag Warning Overhead circuit mile days - HFTD Zone 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					Red Flag Warning Overhead circuit mile days, see above for definition	BVES does not have any Zone 1 HFTD designations
	1.c.	Red Flag Warning Overhead circuit mile days - HFTD Tier 2	611.4907	2969.828	3292.868	2218.514	1327.5868	0	0	802.8829	1694.439	0	0	0	786.1125					Red Flag Warning Overhead circuit mile days, see above for definition	The entirety of the utility's service territory is in HFTD Tier 2 with the exception of 1.27 miles of the Radford 34.5 kV line which are HFTD Tier 3. The data above apply to all of the circuits within the utility's service territory.
	1.d.	Red Flag Warning Overhead circuit mile days - HFTD Tier 3	3.70459	17.99209	19.94916	13.44041	8.04291	0	0	4.8641	10.26541	0	0	0	4.7625					Red Flag Warning Overhead circuit mile days, see above for definition	The entirety of the utility's service territory is in HFTD Tier 2 with the exception of 1.27 miles of the Radford 34.5 kV line which are HFTD Tier 3. The data above apply to all of the circuits within the utility's service territory. As of Q1 2022, Tier 3 circuit miles for the Radford line was corrected to 1.5 miles versus previously recorded units ofm 1.27 circuit miles
	1.e.	Red Flag Warning Overhead circuit mile days - Non-HFTD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					Red Flag Warning Overhead circuit mile days, see above for definition	BVES does not have any applicable non-HFTD designations
2. Wind conditions	2.a.	High wind warning overhead circuit mile days	NA	NA	NA	NA	NA	1018.647	0	0	832.6332	1116.083	0	0	536.1078					Sum of overhead circuit miles of utility grid subject to High Wind Warnings (HWW, as defined by the National Weather Service) each day within a given time period, calculated as the number of overhead circuit miles that were under an HWW multiplied by the number of days those miles were under said HWW. For example, if 100 overhead circuit miles were under an HWW for 1 day, and 10 of those miles were under HWW for an additional day, then the total HWW OH circuit mile days would be 110.	BVES has not historically tracked these types of hazard warnings prior to 2020. Going forward, BVES will include this metric with ongoing recordkeeping as confirmed with the utility's weather monitoring third-party. Q3 2021 QDR Update: Additional data was made available for Q1 following Q3 filling and the entries were updated
3. Other	3.a.	Other relevant weather pattern metrics tracked (add additional rows as needed)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						Additional weather pattern metrics tracked located in Table 3

D.7 QDR Table 7.1

Utility	Bear Valley Electric Service, Inc.
Table No.	7.1
Date Modified	4/14/2022

Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 Q4 should be actual numbers. 2022 Q1 - 2024 should be projected. In future submissions update projected numbers with actuals

Table 7.1: Key recent and projected drivers of risk events

					Number of risk events														Projected risk events										
Risk Event category	Cause category	#	Sub-cause category	Are risk events tracked for ignition driver? (yes / no	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
Wire down event - Distribution	1. Contact from object - Distribution	1.a.	Veg. contact- Distribution	Yes	NA	13	4	2	3	2	0	0	0	0	0	1	1	1	1	1	1					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		1.b.	Animal contact- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		1.c.	Balloon contact- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		1.d.	Vehicle contact- Distribution	Yes	NA	2	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		1.e.	Other contact from object - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	2. Equipment / facility failure - Distribution	2.a.	Connector damage or failure- Distribution	Yes	NA	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.b.	Splice damage or failure — Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.c.	Crossarm damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.d.	Insulator damage or failure- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.e.	Lightning arrestor damage or failure- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.f.	Tap damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.g.	Tie wire damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		2.h.	Other - Distribution	Yes	NA	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	3. Wire-to-wire contact - Distribution	3.a.	Wire-to-wire contact / contamination- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	4. Contamination - Distribution	4.a.	Contamination - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	5. Utility work / Operation	5.a.	Utility work / Operation	Yes	NA	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	6. Vandalism / Theft - Distribution	6.a.	Vandalism / Theft - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	7. Other- Distribution	7.a.	All Other- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	8. Unknown- Distribution	8.a.	Unknown - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020

Wire down event - Transmission	9. Contact from object - Transmission	9.a.	Veg. contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		9.b.	Animal contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		9.c.	Balloon contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		9.d.	Vehicle contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		9.e.	Other contact from object - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	10. Equipment / facility failure - Transmission	10.a.	Connector damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.b.	Splice damage or failure — Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.c.	Crossarm damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.d.	Insulator damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.e.	Lightning arrestor damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.f.	Tap damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.g.	Tie wire damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		10.h.	Other - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	11. Wire-to-wire contact - Transmission	11.a.	Wire-to-wire contact / contamination- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	12. Contamination - Transmission	12.a.	Contamination - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	13. Utility work / Operation	13.a.	Utility work / Operation	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	14. Vandalism / Theft - Transmission	14.a.	Vandalism / Theft - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	15. Other- Transmission	15.a.	All Other- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	16. Unknown- Transmission	16.a.	Unknown - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.

Outage - Distribution	17. Contact from object - Distribution	17.a.	Veg. contact- Distribution	Yes	NA	15	12	7	2	1	1	0	1	0	0	1	5	1	1	1	1	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		17.b.	Animal contact- Distribution	Yes	NA	0	1	0	1	0	0	0	1	1	1	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		17.c.	Balloon contact- Distribution	Yes	NA	1	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		17.d.	Vehicle contact- Distribution	Yes	NA	5	9	1	0	0	2	2	0	2	1	1	2	1	1	1	1	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		17.e.	Other contact from object - Distribution	Yes	NA	2	1	0	0	0	0	1	2	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	18. Equipment / facility failure - Distribution	18.a.	Capacitor bank damage or failure- Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.b.	Conductor damage or failure — Distribution	Yes	NA	0	5	0	1	0	0	1	0	1	0	0	1	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.c.	Fuse damage or failure - Distribution	Yes	NA	15	27	13	2	0	2	4	9	6	0	0	6	3	3	3	3	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.d.	Lightning arrestor damage or failure- Distribution	Yes	NA	0	0	0	0	0	0	9	0	0	0	0	0	1	1	1	1	# risk events (excluding ignitions)	Overload-Lightening were counted here because BVES's categories don't align 1 to 1 and a reference to a blown fuse or trasformer was not made in the comments Projected values based off quarterly average for 2016-2020
		18.e.	Switch damage or failure- Distribution	Yes	NA	1	1	0	1	0	0	0	1	0	0	0	1	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.f.	Pole damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.g.	Insulator and brushing damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.h.	Crossarm damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.i.	Voltage regulator / booster damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.j.	Recloser damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.k.	Anchor / guy damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.l.	Sectionalizer damage or failure - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.m.	Connection device damage or failure - Distribution	Yes	NA	11	25	1	1	0	1	0	1	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.n.	Transformer damage or failure - Distribution	Yes	NA	5	3	0	7	1	0	0	1	1	0	2	2	1	1	1	1	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
		18.o.	Other - Distribution	Yes	NA	0	0	4	3	0	0	2	0	0	0	1	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	19. Wire-to-wire contact - Distribution	19.a.	Wire-to-wire contact / contamination- Distribution	Yes	NA	0	5	4	2	1	0	1	0	0	0	1	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	20. Contamination - Distribution	20.a.	Contamination - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	21. Utility work / Operation	21.a.	Utility work / Operation	Yes	NA	0	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	22. Vandalism / Theft - Distribution	22.a.	Vandalism / Theft - Distribution	Yes	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	23. Other- Distribution	23.a.	All Other- Distribution	Yes	NA	4	1	0	0	0	1	1	0	1	1	5	1	1	1	1	1	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020
	24. Unknown- Distribution	24.a.	Unknown - Distribution	Yes	NA	0	0	0	2	0	0	0	2	0	0	1	3	1	1	1	1	# risk events (excluding ignitions)	Projected values based off quarterly average for 2016-2020

Outage - Transmission	25. Contact from object - Transmission	25.a.	Veg. contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		25.b.	Animal contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		25.c.	Balloon contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		25.d.	Vehicle contact- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		25.e.	Other contact from object - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	26. Equipment / facility failure - Transmission	26.a.	Capacitor bank damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.b.	Conductor damage or failure — Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.c.	Fuse damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.d.	Lightning arrestor damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.e.	Switch damage or failure- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.f.	Pole damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.g.	Insulator and brushing damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.h.	Crossarm damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.i.	Voltage regulator / booster damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.j.	Recloser damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.k.	Anchor / guy damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.l.	Sectionalizer damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.m.	Connection device damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.n.	Transformer damage or failure - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
		26.o.	Other - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	27. Wire-to-wire contact - Transmission	27.a.	Wire-to-wire contact / contamination- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	28. Contamination - Transmission	28.a.	Contamination - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	29. Utility work / Operation	29.a.	Utility work / Operation	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	30. Vandalism / Theft - Transmission	30.a.	Vandalism / Theft - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	31. Other- Transmission	31.a.	All Other- Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.
	32. Unknown- Transmission	32.a.	Unknown - Transmission	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	# risk events (excluding ignitions)	BVES does not own/operate any overhead transmission lines that are 65kV or greater.

D.8 QDR Table 7.2

Utility	Bear Valley Electric Service, Inc.	**Notes:**
Table No.	7.2	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	4/14/2022	Data from 2015 - 2021 should be actual numbers. 2022 and 2023 should be projected. In future submissions update projected numbers with actuals

Table 7.2: Key recent and projected drivers of ignitions

					Number of ignitions							Projected ignitions			
Metric type	**#**	**Ignition driver**	**Line Type**	**HFTD tier**	**Are ignitions tracked for ignition driver? (yes / no)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Unit(s)**	**Comments**
1. Contact from object	1.a.i	Veg. contact	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.a.ii	Veg. contact	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.a.iii	Veg. contact	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.a.iv	Veg. contact	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.a.v	Veg. contact	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.a.vi	Veg. contact	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.a.vii	Veg. contact	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.a.viii	Veg. contact	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.a.ix	Veg. contact	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.a.x	Veg. contact	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.b.i	Animal contact	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.b.ii	Animal contact	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.b.iii	Animal contact	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.b.iv	Animal contact	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.b.v	Animal contact	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.b.vi	Animal contact	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.b.vii	Animal contact	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.b.viii	Animal contact	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.b.ix	Animal contact	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.b.x	Animal contact	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.c.i	Balloon contact	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.c.ii	Balloon contact	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.c.iii	Balloon contact	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.c.iv	Balloon contact	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.c.v	Balloon contact	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.c.vi	Balloon contact	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.c.vii	Balloon contact	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.c.viii	Balloon contact	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.c.ix	Balloon contact	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.c.x	Balloon contact	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.d.i	Vehicle contact	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.d.ii	Vehicle contact	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1

	1.d.iii	Vehicle contact	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.d.iv	Vehicle contact	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.d.v	Vehicle contact	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.d.vi	Vehicle contact	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.d.vii	Vehicle contact	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.d.viii	Vehicle contact	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.d.ix	Vehicle contact	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.d.x	Vehicle contact	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.e.i	Other contact from object	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.e.ii	Other contact from object	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	1.e.iii	Other contact from object	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.e.iv	Other contact from object	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.e.v	Other contact from object	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	1.e.vi	Other contact from object	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.e.vii	Other contact from object	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.e.viii	Other contact from object	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.e.ix	Other contact from object	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	1.e.x	Other contact from object	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2. Equipment / facility failure	2.a.i	Capacitor bank damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.a.ii	Capacitor bank damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.a.iii	Capacitor bank damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.a.iv	Capacitor bank damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.a.v	Capacitor bank damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.a.vi	Capacitor bank damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.a.vii	Capacitor bank damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.a.viii	Capacitor bank damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.a.ix	Capacitor bank damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.a.x	Capacitor bank damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.b.i	Conductor damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.b.ii	Conductor damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.b.iii	Conductor damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.b.iv	Conductor damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.b.v	Conductor damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.b.vi	Conductor damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.b.vii	Conductor damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.b.viii	Conductor damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.b.ix	Conductor damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.b.x	Conductor damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.c.i	Fuse damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.c.ii	Fuse damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.c.iii	Fuse damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.c.iv	Fuse damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.c.v	Fuse damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.c.vi	Fuse damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.c.vii	Fuse damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.c.viii	Fuse damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.c.ix	Fuse damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.c.x	Fuse damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.d.i	Lightning arrestor damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.d.ii	Lightning arrestor damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.d.iii	Lightning arrestor damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.d.iv	Lightning arrestor damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.d.v	Lightning arrestor damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.d.vi	Lightning arrestor damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.d.vii	Lightning arrestor damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.d.viii	Lightning arrestor damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.d.ix	Lightning arrestor damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.d.x	Lightning arrestor damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.e.i	Switch damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.e.ii	Switch damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.e.iii	Switch damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.e.iv	Switch damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.e.v	Switch damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.e.vi	Switch damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.e.vii	Switch damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.e.viii	Switch damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.e.ix	Switch damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.e.x	Switch damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.f.i	Pole damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.f.ii	Pole damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	2.f.iii	Pole damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.f.iv	Pole damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.f.v	Pole damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	2.f.vi	Pole damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.f.vii	Pole damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.f.viii	Pole damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.f.ix	Pole damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	2.f.x	Pole damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.

2.g.i	Insulator and brushing damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.g.ii	Insulator and brushing damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.g.iii	Insulator and brushing damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.g.iv	Insulator and brushing damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.g.v	Insulator and brushing damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.g.vi	Insulator and brushing damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.g.vii	Insulator and brushing damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.g.viii	Insulator and brushing damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.g.ix	Insulator and brushing damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.g.x	Insulator and brushing damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.h.i	Crossarm damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.h.ii	Crossarm damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.h.iii	Crossarm damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.h.iv	Crossarm damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.h.v	Crossarm damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.h.vi	Crossarm damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.h.vii	Crossarm damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.h.viii	Crossarm damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.h.ix	Crossarm damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.h.x	Crossarm damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.i.i	Voltage regulator / booster damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.i.ii	Voltage regulator / booster damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.i.iii	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.i.iv	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.i.v	Voltage regulator / booster damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.i.vi	Voltage regulator / booster damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.i.vii	Voltage regulator / booster damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.i.viii	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.i.ix	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.i.x	Voltage regulator / booster damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.j.i	Recloser damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.j.ii	Recloser damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.j.iii	Recloser damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.j.iv	Recloser damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.j.v	Recloser damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.j.vi	Recloser damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.j.vii	Recloser damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.j.viii	Recloser damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.j.ix	Recloser damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.j.x	Recloser damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.k.i	Anchor / guy damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.k.ii	Anchor / guy damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.k.iii	Anchor / guy damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.k.iv	Anchor / guy damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015

2.k.v	Anchor / guy damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.k.vi	Anchor / guy damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.k.vii	Anchor / guy damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.k.viii	Anchor / guy damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.k.ix	Anchor / guy damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.k.x	Anchor / guy damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.l.i	Sectionalizer damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.l.ii	Sectionalizer damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.l.iii	Sectionalizer damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.l.iv	Sectionalizer damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.l.v	Sectionalizer damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.l.vi	Sectionalizer damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.l.vii	Sectionalizer damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.l.viii	Sectionalizer damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.l.ix	Sectionalizer damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.l.x	Sectionalizer damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.m.i	Connection device damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.m.ii	Connection device damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.m.iii	Connection device damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.m.iv	Connection device damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.m.v	Connection device damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.m.vi	Connection device damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.m.vii	Connection device damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.m.viii	Connection device damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.m.ix	Connection device damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.m.x	Connection device damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.n.i	Transformer damage or failure	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.n.ii	Transformer damage or failure	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.n.iii	Transformer damage or failure	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.n.iv	Transformer damage or failure	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.n.v	Transformer damage or failure	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.n.vi	Transformer damage or failure	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.n.vii	Transformer damage or failure	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.n.viii	Transformer damage or failure	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.n.ix	Transformer damage or failure	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.n.x	Transformer damage or failure	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.o.i	Other	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.o.ii	Other	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
2.o.iii	Other	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.o.iv	Other	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.o.v	Other	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
2.o.vi	Other	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.o.vii	Other	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.o.viii	Other	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.o.ix	Other	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
2.o.x	Other	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.

3. Wire-to-wire contact	3.a.i	Wire-to-wire contact / contamination	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	3.a.ii	Wire-to-wire contact / contamination	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	3.a.iii	Wire-to-wire contact / contamination	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	3.a.iv	Wire-to-wire contact / contamination	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	3.a.v	Wire-to-wire contact / contamination	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	3.a.vi	Wire-to-wire contact / contamination	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	3.a.vii	Wire-to-wire contact / contamination	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	3.a.viii	Wire-to-wire contact / contamination	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	3.a.ix	Wire-to-wire contact / contamination	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	3.a.x	Wire-to-wire contact / contamination	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
4. Contamination	4.a.i	Contamination	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	4.a.ii	Contamination	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	4.a.iii	Contamination	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	4.a.iv	Contamination	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	4.a.v	Contamination	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	4.a.vi	Contamination	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	4.a.vii	Contamination	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	4.a.viii	Contamination	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	4.a.ix	Contamination	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	4.a.x	Contamination	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
5. Utility work / Operation	5.a.i	Utility work / Operation	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	5.a.ii	Utility work / Operation	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	5.a.iii	Utility work / Operation	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	5.a.iv	Utility work / Operation	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	5.a.v	Utility work / Operation	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	5.a.vi	Utility work / Operation	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	5.a.vii	Utility work / Operation	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	5.a.viii	Utility work / Operation	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	5.a.ix	Utility work / Operation	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	5.a.x	Utility work / Operation	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
6. Vandalism / Theft	6.a.i	Vandalism / Theft	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	6.a.ii	Vandalism / Theft	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	6.a.iii	Vandalism / Theft	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	6.a.iv	Vandalism / Theft	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	6.a.v	Vandalism / Theft	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	6.a.vi	Vandalism / Theft	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	6.a.vii	Vandalism / Theft	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	6.a.viii	Vandalism / Theft	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	6.a.ix	Vandalism / Theft	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	6.a.x	Vandalism / Theft	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
7. Other	7.a.i	All Other	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	7.a.ii	All Other	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	7.a.iii	All Other	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	7.a.iv	All Other	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	7.a.v	All Other	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	7.a.vi	All Other	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	7.a.vii	All Other	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	7.a.viii	All Other	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	7.a.ix	All Other	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	7.a.x	All Other	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
8. Unknown	8.a.i	Unknown	Distribution	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	8.a.ii	Unknown	Distribution	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not have any service territory within the Non-HFTD or Zone 1
	8.a.iii	Unknown	Distribution	HFTD Tier 2	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	8.a.iv	Unknown	Distribution	HFTD Tier 3	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	8.a.v	Unknown	Distribution	System	Yes	NA	0	0	0	0	0	0	0	0	# ignitions	No data available in 2015
	8.a.vi	Unknown	Transmission	Non-HFTD	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	8.a.vii	Unknown	Transmission	HFTD Zone 1	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	8.a.viii	Unknown	Transmission	HFTD Tier 2	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	8.a.ix	Unknown	Transmission	HFTD Tier 3	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.
	8.a.x	Unknown	Transmission	System	No	NA	NA	NA	NA	NA	NA	NA	NA	NA	# ignitions	BVES does not own or manage transmission lines/equipment rated at or above 65 kV.

D.9 QDR Table 8

Utility	Service, Inc.
Table No.	8
Date Modified	4/14/2022

Table 8: State of service territory and utility equipment

Metric type	#	Outcome metric name	Non-HFTD 2015	HFTD Zone 1 2015	HFTD Tier 2 2015	HFTD Tier 3 2015	Non-HFTD 2016	HFTD Zone 1 2016	HFTD Tier 2 2016	HFTD Tier 3 2016	Non-HFTD 2017	HFTD Zone 1 2017	HFTD Tier 2 2017	HFTD Tier 3 2017	Non-HFTD 2018	HFTD Zone 1 2018	HFTD Tier 2 2018	HFTD Tier 3 2018
1. State of service territory and equipment in urban areas	1.a.	Circuit miles (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	1.b.	Circuit miles in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	1.c.	Number of critical facilities (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	1.d.	Number of critical facilities in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

#	Non-HFTD 2019	HFTD Zone 1 2019	HFTD Tier 2 2019	HFTD Tier 3 2019	Non-HFTD 2020	HFTD Zone 1 2020	HFTD Tier 2 2020	HFTD Tier 3 2020	Non-HFTD 2021	HFTD Zone 1 2021	HFTD Tier 2 2021	HFTD Tier 3 2021	Unit(s)	Comments
1.a.	NA	NA	NA	NA	NA	NA	262.2	2.8	NA	NA	184.74	0	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.b.	NA	NA	NA	NA	NA	NA	262.2	2.8	NA	NA	184.74	0	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.c.	NA	NA	NA	NA	NA	NA	14	0	NA	NA	12	0	Number of critical facilities	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.d.	NA	NA	NA	NA	NA	NA	14	0	NA	NA	12	0	Number of critical facilities in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

1.e.	Number of customers (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	24500	0	NA	NA	21097	0	Number of customers	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.f.	Number of customers in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	24500	0	NA	NA	21097	0	Number of customers in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.h.	Number of customers belonging to access and functional needs populations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines	BVES does not have any transmission circuits.
1.j.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines in WUI	BVES does not have any transmission circuits.
1.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	208.1	2.8	NA	NA	146.82	0	Circuit miles of overhead distribution lines	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.l.	Circuit miles of overhead distribution lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	208.1	2.8	NA	NA	146.82	0	Circuit miles of overhead distribution lines in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.m.	Number of substations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13	0	NA	NA	8	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
1.n	Number of substations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13	0	NA	NA	8	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

	1.o.	Number of weather stations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17	1	NA	NA	8	0	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.p.	Number of weather stations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17	1	NA	NA	8	0	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
2. State of service territory and equipment in rural areas	2.a.	Circuit miles (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	262.2	2.8	NA	NA	78.45	1.64	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.b.	Circuit miles in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	262.2	2.8	NA	NA	78.45	1.64	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.c.	Number of critical facilities (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	14	0	NA	NA	2	0	Number of critical facilities	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.d.	Number of critical facilities in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	14	0	NA	NA	2	0	Number of critical facilities in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.e.	Number of customers (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	24500	0	NA	NA	3530	1	Number of customers	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.f.	Number of customers in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	24500	0	NA	NA	3530	1	Number of customers in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.h.	Number of customers belonging to access and functional needs populations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines	BVES does not have any transmission circuits.
	2.j.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines in WUI	BVES does not have any transmission circuits.

	2.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	208.1	2.8	NA	NA	61.63	1.64	Circuit miles of overhead distribution lines	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.l.	Circuit miles of overhead distribution lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	208.1	2.8	NA	NA	61.63	1.64	Circuit miles of overhead distribution lines in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.m.	Number of substations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13	0	NA	NA	5	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.n	Number of substations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	13	0	NA	NA	5	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.o.	Number of weather stations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17	1	NA	NA	10	2	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.p.	Number of weather stations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17	1	NA	NA	10	2	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3. State of service territory and equipment in highly rural areas	3.a.	Circuit miles (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.b.	Circuit miles in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.c.	Number of critical facilities (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of critical facilities	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.d.	Number of critical facilities in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of critical facilities in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.e.	Number of customers (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.f.	Number of customers in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

3.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.h.	Number of customers belonging to access and functional needs populations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of customers belonging to access and functional needs populations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines	BVES does not have any transmission circuits.
3.j.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead transmission lines in WUI	BVES does not have any transmission circuits.
3.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead distribution lines	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.l.	Circuit miles of overhead distribution lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles of overhead distribution lines in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.m.	Number of substations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.n	Number of substations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.o.	Number of weather stations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.p.	Number of weather stations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this quarter as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

D.10 QDR Table 9

Utility	Service, Inc.	Notes:
Table No.	9	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Only report changes expected within the target year.
Date Modified	4/14/2022	For example, if 20 net overhead circuit miles are planned for addition by 2023, with 15 being added by 2022 and 5 more added by 2023, then report "15" for 2022 and "5" for 2023. Do not report cumulative change across years. In this case, do not report "20" for 2023, but instead the number planned to be added for just that year, which is "5".

Table 9: Location of actual and planned utility equipment additions or removal year over year

			Actual								Projected					
			Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone	HFTD Tier 2	HFTD Tier 3		
Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
1. Planned utility equipment net addition (or removal) year over year - in urban	1.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles	BVES does not have any transmission circuits.
	1.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.c.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
	1.d.	Circuit miles of overhead distribution lines in WUI	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.e.	Number of substations (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.f.	Number of substations in WUI	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

	1.g.	Number of weather stations (including WUI and non-WUI)	NA	NA	8	0	NA	NA	0	0	NA	NA	0	0	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.h.	Number of weather stations in WUI	NA	NA	8	0	NA	NA	0	0	NA	NA	0	0	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
2. Planned utility equipment net addition (or removal) year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles	BVES does not have any transmission circuits.
	2.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.c.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
	2.d.	Circuit miles of overhead distribution lines in WUI	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.e.	Number of substations (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.f.	Number of substations in WUI	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.g.	Number of weather stations (including WUI and non-WUI)	NA	8	0	0	NA	NA	1	1	NA	NA	0	0	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

	2.h.	Number of weather stations in WUI	NA	8	0	0	NA	NA	1	1	NA	NA	0	0	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3. Planned utility equipment net addition (or removal) year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES does not have any transmission circuits.
	3.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.c.	Circuit miles of overhead transmission lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
	3.d.	Circuit miles of overhead distribution lines in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.e.	Number of substations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.f.	Number of substations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.g.	Number of weather stations (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	3.h.	Number of weather stations in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

D.11 QDR Table 10

Utility	Service, Inc.	Notes:
Table No.	10	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	4/14/2022	In future submissions update planned upgrade numbers with actuals
		In the comments column on the far-right, enter the relevant program target(s) associated

Table 10: Location of actual and planned utility infrastructure upgrades year over year

			Actual								Projected					
			Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone	HFTD Tier 2	HFTD Tier 3		
Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
1. Planned utility infrastructure upgrades year over year - in urban areas	1.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES does not have any transmission circuits.
	1.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	NA	NA	0	0	NA	NA	6.87	0	NA	NA	13.5	0	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
	1.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	NA	NA	0	0	NA	NA	6.87	0	NA	NA	13.5	0	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.e.	Number of substations planned for upgrades (including WUI and non-WUI)	NA	NA	1	0	NA	NA	0	0	NA	NA	0	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.f.	Number of substations planned for upgrades in WUI	NA	NA	1	0	NA	NA	0	0	NA	NA	0	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	1.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

	1.h.	Number of weather stations planned for upgrades in WUI	NA	NA	0	0	NA	NA	0	0	NA	NA	0	0	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
2. Planned utility infrastructure upgrades year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES does not have any transmission circuits.
	2.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	NA	NA	7.8	0	NA	NA	5.81	0	NA	NA	1.3	1.52	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
	2.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	NA	NA	7.8	0	NA	NA	5.81	0	NA	NA	1.3	1.52	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.e.	Number of substations planned for upgrades (including WUI and non-WUI)	NA	NA	1	0	NA	NA	1	0	NA	NA	0	0	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.f.	Number of substations planned for upgrades in WUI	NA	NA	1	0	NA	NA	1	0	NA	NA	0	0	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	NA	NA	0	0	0	0	0	0	NA	NA	0	0	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
	2.h.	Number of weather stations planned for upgrades in WUI	NA	NA	0	0	0	0	0	0	NA	NA	0	0	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3. Planned utility infrastructure upgrades year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES does not have any transmission circuits.

3.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently determined as rural, but may be revised due to calibration of coordinates at a future date. BVES plans to harden bare wire on 34.5kV lines with 4.3 circuit miles of hardening per year. The planned projects are reported under "Rural" for this submission.
3.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES does not have any transmission circuits.
3.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Circuit miles in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps. A small extension of the Radford line, serving no customers, is currently determined as rural, but may be revised due to calibration of coordinates at a future date. BVES plans to harden bare wire on 34.5kV lines with 4.3 circuit miles of hardening per year. The planned projects are reported under "Rural" for this submission.
3.e.	Number of substations planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.f.	Number of substations planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of substations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.
3.h.	Number of weather stations planned for upgrades in WUI	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Number of weather stations in WUI	BVES recently executed GIS mapping of its WUI locations and found that a majority of the service area and assets fall under rural, with a proportion of the area surrounding the lake considered an urban area by the U.S. Census Data. BVES is continuing to enhance it's risk and asset maps and will provide updates in the next EC WMP QDR. A small extension of the Radford line, serving no customers, is currently assumed as highly rural, but may be revised due to calibration of coordinates at a future date. No reporting in the "highly rural" categories is found in this QDR submission as BVES is continuing to enhance its GIS capabilities to better quantify the overlapping territory.

D.12 QDR Table 11

Utility	Service, Inc.	Notes:
Table No.	11	"PSPS" = Public Safety Power Shutoff
		In future submissions update planned
Date Modified	4/14/2022	upgrade numbers with actuals

Table 11: Recent use of PSPS and other PSPS metrics

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
			Actual													Projected									
1. Recent use of PSPS	1.a.	Frequency of PSPS events (total)	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability, per year	
	1.b.	Scope of PSPS events (total)	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Circuit-events, measured in number of events multiplied by number of circuits de-energized per year	
	1.c.	Duration of PSPS events (total)	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Customer hours per year	
2. Customer hours of PSPS and other outages	2.a.	Customer hours of planned outages including PSPS (total)	NA	87254	5090613	359243	31890	0	2582	0	184	0	5	0	0	346	346	346	346	346	346	346	346	Total customer hours of planned outages per year	Customer Count: 2016 - 23876 2017 - 23975 2018 - 24296 2019 - 24366 2020 - 24446 2021 - 21097 Quarterly average of years 2018 and 2019 for projected values.
	2.b.	Customer hours of unplanned outages, not including PSPS (total)	NA	7726110	8686856	4415849	6306302	1127	2330	53124	116978	23161	25100	33061	82853	42217	42217	42217	42217	42217	42217	42217	42217	Total customer hours of unplanned outages per year	Quarterly average of years 2018 and 2019 for projected values.
	2.c.	System Average Interruption Duration Index (SAIDI) (including PSPS)	NA	327.25	574.66	196.54	260.12	2.77	12.06	130.39	287.56	56.58	61.24	80.53	201.82	104	104	104	104	104	104	104	104	SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer interruptions) / Total number of customers served	Quarterly average of years 2018 and 2019 for projected values.
	2.d.	System Average Interruption Duration Index (SAIDI) (excluding PSPS)	NA	327.25	574.66	196.54	260.12	2.77	12.06	130.39	287.56	56.58	61.24	80.53	201.82	104	104	104	104	104	104	104	104	SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer interruptions) / Total number of customers served	Quarterly average of years 2018 and 2019 for projected values.
	2.e.	System Average Interruption Frequency Index (SAIFI) (including PSPS)	NA	2.69	3.94	2.92	1.93	0.06	0.20	1.52	2.94	0.50	1.00	1.64	2.55	1	1	1	1	1	1	1	1	SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of customers served)	Quarterly average of years 2018 and 2019 for projected values.
	2.f.	System Average Interruption Frequency Index (SAIFI) (excluding PSPS)	NA	2.69	3.94	2.92	1.93	0.06	0.20	1.52	2.94	0.50	1.00	1.64	2.55	1	1	1	1	1	1	1	1	SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of customers served)	Quarterly average of years 2018 and 2019 for projected values.
3. Critical infrastructure impacted by PSPS	3.a.	Critical infrastructure impacted by PSPS	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Number of critical infrastructure (in accordance with D.19-05-042) locations impacted per hour multiplied by hours offline per year	Quarterly average of years 2018 and 2019 for projected values.
4. Community outreach of PSPS metrics	4.a.	# of customers impacted by PSPS	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	Quarterly average of years 2018 and 2019 for projected values.
	4.b.	# of medical baseline customers impacted by PSPS	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	Quarterly average of years 2018 and 2019 for projected values.
	4.c.	# of customers notified prior to initiation of PSPS event	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer was notified as a separate customer)	Quarterly average of years 2018 and 2019 for projected values.
	4.d.	# of medical baseline customers notified prior to initiation of PSPS event	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer was notified as a separate customer)	Quarterly average of years 2018 and 2019 for projected values.
	4.e.	% of customers notified prior to a PSPS event impacting them	NA	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	=4.a. / 4.c.	
	4.f.	% of medical baseline customers notified prior to a PSPS event impacting them	NA	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	=4.a. / 4.c.	
5. Other PSPS metrics	5.a.	Number of PSPS de-energizations	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Number of de-energizations	Quarterly average of years 2018 and 2019 for projected values.
	5.b.	Number of customers located on de-energized circuit	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Number of customers	Quarterly average of years 2018 and 2019 for projected values.
	5.c.	Customer hours of PSPS per RFW OH circuit mile day	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	=1.c. / RFW OH circuit mile days in time period	Quarterly average of years 2018 and 2019 for projected values.
	5.d.	Frequency of PSPS events (total) - High Wind Warning wind conditions	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Events over time period that overlapped with a High Wind Warning as defined by the National Weather Service	Quarterly average of years 2018 and 2019 for projected values.
	5.e.	Scope of PSPS events (total) - High Wind Warning wind conditions	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Estimated customers impacted over time period that overlapped with a High Wind Warning as defined by the National Weather Service	Quarterly average of years 2018 and 2019 for projected values.
	5.f.	Duration of PSPS events (total) - High Wind Warning wind conditions	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Customer hours over time period that overlapped with a High Wind Warning as defined by the National Weather Service	Quarterly average of years 2018 and 2019 for projected values.

D.13 QDR Table 12

Utility	ar Valley Electric Service, Inc.
Table No.	12
Date Modified	4/14/2022

Notes:
Risk-Spend-Efficiency (RSE) is defined as "An estimate of the cost-effectiveness of initiative, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."
CAPEX = Capital expenditure; OPEX = Operating

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initiative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compliance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ";"	If spend not disaggregated by category, note spend category or mark general operations	Comments
Other	Risk Assessment & Mapping	7.3.1.1.	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Contact with vegetation	Other contact with object	2021	3.28	NA	NA	3.28	3.28	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Bear Valley Electric Service has implemented the CPUC Fire Threat Map Adopted in D.17-12-024 December 14, 2017 throughout its service territory. This map shows the CPUC-designated fire hazard zone tiers within BVES's service territory, which quantify specific geography that could be subject to elevated fire risk under historically viable fire weather conditions. BVES has also identified seven sections of "at-risk" areas within its service territory based on the type of distribution facilities (overhead bare conductors, high voltage,
Other	Risk Assessment & Mapping	7.3.1.2.	Climate-driven risk map and modelling based on various relevant weather scenarios	Contact with vegetation	Other contact with object	2021	3.28	NA	NA	3.28	3.28	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Bear Valley Electric Service has implemented the CPUC Fire Threat Map Adopted in D.17-12-024 December 14, 2017 throughout its service territory. This map shows the CPUC-designated fire hazard zone tiers within BVES's service territory, which quantify specific geography that could be subject to elevated fire risk under historically viable fire weather conditions. BVES has also identified seven sections of "at-risk" areas within its service territory based
Other	Risk Assessment & Mapping	7.3.1.3.	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Contact with vegetation	Other contact with object	2021	3.28	NA	NA	3.28	3.28	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Bear Valley Electric Service has implemented the CPUC Fire Threat Map Adopted in D.17-12-024 December 14, 2017 throughout its service territory. This map shows the CPUC-designated fire hazard zone tiers within BVES's service territory, which quantify specific geography that could be subject to elevated fire risk under historically viable fire weather conditions. BVES has also
Other	Risk Assessment & Mapping	7.3.1.4.	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	Contact with vegetation	Other contact with object	2020	3.28	NA	NA	3.28	3.28	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Bear Valley Electric Service has implemented the CPUC Fire Threat Map Adopted in D.17-12-024 December 14, 2017 throughout its service territory. This map shows the CPUC-designated fire hazard zone tiers within BVES's service territory, which quantify specific geography that could be subject to elevated
Other	Risk Assessment & Mapping	7.3.1.5.	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Contact with vegetation	Other contact with object	2021	3.28	NA	NA	3.28	3.28	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Bear Valley Electric Service has implemented the CPUC Fire Threat Map Adopted in D.17-12-024 December 14, 2017 throughout its service territory. This map shows the CPUC-designated fire hazard zone tiers within BVES's service territory, which quantify specific geography that could be subject to elevated fire risk under historically viable fire weather conditions. BVES has also
Other	Situational Awareness & Forecasting	7.3.2.1.	Advanced weather monitoring and weather stations	Contact with vegetation	Wire-to-wire contact	2018	8.4	NA	NA	8.4	8.4	GRC	WMP Memorandum Account and GRC	In Compliance	GO 95		All planned weather stations deployed by 2021
Other	Situational Awareness & Forecasting	7.3.2.2.	Continuous monitoring sensors	Contact with vegetation	Other contact with object	2020	3.98	NA	NA	3.98	3.98	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		All planned HD cameras deployed by 2021
Other	Situational Awareness & Forecasting	7.3.2.3.	Fault indicators for detecting faults on electric lines and equipment	Contact with vegetation	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		Situational Awareness Hardware Program // Fault Indicator Installation Project BVES is monitoring Down wire Detection Technology and once the technology is ready for field use, BVES will develop a Down Wire Detection Installment Program in future WMPs.
Other	Situational Awareness & Forecasting	7.3.2.4.	Forecast of a fire risk index, fire potential index, or similar	Contact with vegetation	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	NA	GO 166 Standard 1.E		BVES's Subject Matter Expert evaluates the frequency of potential ignition events versus a set of impact categories (reliability, compliance, quality of service, safety and environmental) to develop total risk impact and scores. In addition, no specific incremental spend has been identified for this initiative. Bear Valley Electric Service does not have a proprietary model or methodology for evaluating the potential impact of ignitions. Additional modeling support will be added in 2022 through Technosylva
Other	Situational Awareness & Forecasting	7.3.2.5.	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Contact with vegetation	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		During high fire threat weather that could lead to PSPS events, BVES does deploy crews to monitor conditions in the field, in the high threat areas.
Other	Situational Awareness & Forecasting	7.3.2.6.	Weather forecasting and estimating impacts on electric lines and equipment	Contact with vegetation	Wire-to-wire contact	2018	0.26	NA	NA	0.26	0.26	NA	WMP Memorandum Account	Exceeding Compliance	ESRB-8		During high fire threat weather that could lead to PSPS events, BVES does deploy crews to monitor conditions in the field, in the high threat areas.
Grid hardening	Grid Design & System Hardening	7.3.3.1.	Capacitor maintenance and replacement program	Equipment failure	Contamination	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		Bear Valley Electric Service has 25 capacitor locations and maintenance and replacement is included in the company's standard inspection, maintenance, and replacement protocols. The capacitors are fixed (either on service or off service) and part of our Overhead Facility Patrol and Inspection program objectives is to ensure they are not leaking or visually damaged.
Grid hardening	Grid Design & System Hardening	7.3.3.2.	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	Equipment failure	PSPS - for sectionalization, etc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		Circuit breakers are generally installed for all distribution circuits to detect fault current and protect equipment in the event that a fault is detected. Circuit breaker replacement and maintenance is included in the company's standard inspection, maintenance, and replacement protocols. Any enhanced inspections or accelerated correction timeframe/replacements are captured in Asset management and inspections under Section 7.3 of the WMP. Installation of system automation equipment.
Grid hardening	Grid Design & System Hardening	7.3.3.3.	Covered conductor installation	Contact with vegetation	Wire-to-wire contact	2019	0.4	NA	NA	0.4	0.4	NA	WMP Memorandum Account	NA	NA		Covered Conductor Project - (4kV & 34 kV Systems) 2019 and 2020 costs include the Covered Conductor Replacement Pilot Program and the Covered Conductor Wrap Pilot Program. Program replaces all 205.2 line miles of 34.5 kV overhead sub-transmission lines (beginning in 2020) and 4 kV distribution lines (beginning in 2021) with covered wire over a 6-year period, 2020-2026.
Grid hardening	Grid Design & System Hardening	7.3.3.4.	Covered conductor maintenance	Contact with vegetation	Wire-to-wire contact	2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		BVES will continue to evaluate covered conductor maintenance initiatives specific to wildfire mitigation.
Grid hardening	Grid Design & System Hardening	7.3.3.5.	Crossarm maintenance, repair, and replacement	Equipment failure	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		Routine crossarm maintenance, repair, and replacement are included in the company's standard inspection and correction programs, with an accelerated timeline for correction under the company's Inspection program improvement
Grid hardening	Grid Design & System Hardening	7.3.3.6.	Distribution pole replacement and reinforcement, including with composite poles	Equipment failure	Wire-to-wire contact	2018	0.09	NA	NA	0.09	0.09	D. 19-08-027	NA	In Compliance	GO 95		Test all poles to loading standards, GO95 requirements, intrusive inspection criteria and age and then, replaces or remediates non-compliant poles.
Grid hardening	Grid Design & System Hardening	7.3.3.7.	Expulsion fuse replacement	Equipment failure	Other contact with object	2018	0.09	NA	NA	0.09	0.09	R. 18-10-007	NA	Exceeding Compliance	GO 95		Replaces all conventional (expulsion) fuses with current limiting (ELF) and electronic fuses (Fuse TripSavers). Completed in 2021
Grid hardening	Grid Design & System Hardening	7.3.3.8.	Grid topology improvements to mitigate or reduce PSPS events	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System Hardening	7.3.3.9.	Installation of system automation equipment	Equipment failure	Wire-to-wire contact	2019	0.26	NA	NA	0.26	0.26	D. 19-08-027	NA	In Compliance	NA		Install grid automation. Fully instruments and automates BVES grid. Consists of installing a service area wide network operating on a SCADA system, substation automation, remote fault indicators, remote metering and power sensors and remote switching equipment to enable BVES to significantly improve its capability to detect and isolate faults rapidly before ever rolling out a crew.
Grid hardening	Grid Design & System Hardening	7.3.3.10.	Maintenance, repair, and replacement of connectors, including hotline clamps	Equipment failure	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		Fault Isolation Localization and Service Restoration (FLISR)
Grid hardening	Grid Design & System Hardening	7.3.3.11.	Mitigation of impact on customers and other residents affected during PSPS event	PSPS - for sectionalization, etc.	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System Hardening	7.3.3.12.	Other corrective action	Other contact with object	Equipment failure	2019	0.01	NA	NA	0.01	0.01	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		
Grid hardening	Grid Design & System Hardening	7.3.3.13.	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Equipment failure	Contamination	2018	0.36	NA	NA	0.36	0.36	GRC	NA	In Compliance	GO 95		
Grid hardening	Grid Design & System Hardening	7.3.3.14.	Transformers maintenance and replacement	Equipment failure	Contamination	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		
Grid hardening	Grid Design & System Hardening	7.3.3.15.	Transmission tower maintenance and replacement			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System Hardening	7.3.3.16.	Undergrounding of electric lines and/or equipment	Contact with vegetation	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		
Grid hardening	Grid Design & System Hardening	7.3.3.17.	Updates to grid topology to minimize risk of ignition in HFTDs	PSPS - for sectionalization, etc.	Contact with vegetation	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		Other grid design and system hardening programs include, as a component, grid topology improvements to minimize the risk of ignition in the HFTD. BVES recognizes that it is challenging to mitigate wildfire risk through grid topology changes alone and therefore focuses more on augmentation of existing circuitry through system hardening efforts.
Asset inspection	Asset Management & Inspections	7.3.4.1.	Detailed inspections of distribution electric lines and equipment	Contamination	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		
Asset inspection	Asset Management & Inspections	7.3.4.2.	Detailed inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.3.	Improvement of inspections	Equipment failure	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	R. 18-10-007	NA	In Compliance	GO 95; GO 165		
Asset inspection	Asset Management & Inspections	7.3.4.4.	Infrared inspections of distribution electric lines and equipment	Other contact with object	Equipment failure	2018	0.8	NA	NA	0.8	0.8	GRC	NA	Exceeding Compliance	Go 95		Contract Exacter Services. Conduct survey of BVES overhead system on 3-year cycle using infrared, ultrasonic and EMI sensors. Approximately 1/3 of OH system surveyed each year." to read: "Contract Exacter Services. Conduct survey of BVES overhead system using infrared, ultrasonic and EMI sensors.
Asset inspection	Asset Management & Inspections	7.3.4.5.	Infrared inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.6.	Intrusive pole inspections	Equipment failure	Contamination	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.7.	LiDAR inspections of distribution electric lines and equipment	Other contact with object	Equipment failure	2018	0.7	NA	NA	0.7	0.7	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		Conduct LiDAR surveys of BVES overhead system on a semi-annual basis.
Asset inspection	Asset Management & Inspections	7.3.4.8.	LiDAR inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.9.	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		BVES has a contract with a supplier t conduct annual 3rd Part Ground Patrols.
Asset inspection	Asset Management & Inspections	7.3.4.10.	Other discretionary inspection of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.11.	Patrol inspections of distribution electric lines and equipment	Other contact with object	Equipment failure	2018	0.09	NA	NA	0.09	0.09	NA	WMP Memorandum Account	Exceeding Compliance	GO 95		
Asset inspection	Asset Management & Inspections	7.3.4.12.	Patrol inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management & Inspections	7.3.4.13.	Pole loading assessment program to determine safety factor	Equipment failure	Contamination	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		

WMP Initiative #	2019 Actual CAPEX ($ Territory	2019 CAPEX ($ HFTD	2019 OPEX ($ Territory	2019 OPEX ($ HFTD	2019 Line miles treated Territory	2019 Line miles treated HFTD	2019 Alternative units (if used)	2020 CAPEX ($ Territory	2020 CAPEX ($ HFTD	2020 OPEX ($ Territory	2020 OPEX ($ HFTD	2020 Line miles treated Territory	2020 Line miles treated HFTD	2020 Alternative units (if used)	2021 CAPEX ($ thousands) Territory	2021 CAPEX ($ thousands) HFTD	2021 OPEX ($ thousands) Territory	2021 OPEX ($ thousands) HFTD	2021 Line miles treated Territory	2021 Line miles treated HFTD	2021 Alternative units (if used)	2022 Projected CAPEX ($ thousands) Territory	2022 CAPEX ($ thousands) HFTD	2022 OPEX ($ thousands) Territory	2022 OPEX ($ thousands) HFTD	2022 Line miles to be Territory	2022 Line miles to be HFTD	2022 Alternative units (if used)	2023 CAPEX ($ thousands) Territory	2023 CAPEX ($ thousands) HFTD	2023 OPEX ($ thousands) Territory	2023 OPEX ($ thousands) HFTD	2023 Line miles to be Territory	2023 Line miles to be HFTD	2023 Alternative units (if used)
7.3.1.1.	0	0	5	5	NA	NA	NA	0	0	8.63121	8.63121	NA	NA	NA	0	0	19.818178	19.818178	NA	NA	NA	0	0	29.984364	29.984364	NA	NA	NA	0	0	30.883894	30.883894	NA	NA	NA
7.3.1.2.	0	0	4.7	4.7	NA	NA	NA	0	0	8.17694	8.17694	NA	NA	NA	0	0	19.3766197	19.3766197	NA	NA	NA	0	0	8.2	8.2	NA	NA	NA	0	0	8.4	8.4	NA	NA	NA
7.3.1.3.	0	0	3.9	3.9	NA	NA	NA	0	0	6.81411	6.81411	NA	NA	NA	0	0	18.051945	18.051945	NA	NA	NA	0	0	28.171796	28.171796	NA	NA	NA	0	0	29.01695	29.01695	NA	NA	NA
7.3.1.4.	0	0	3.5	3.5	NA	NA	NA	0	0	6.1327	6.1327	NA	NA	NA	0	0	17.3896077	17.3896077	NA	NA	NA	0	0	27.492083	27.492083	NA	NA	NA	0	0	28.316845	28.316845	NA	NA	NA
7.3.1.5.	0	0	3.7	3.7	NA	NA	NA	0	0	6.35984	6.35984	NA	NA	NA	0	0	17.6103868	17.6103868	NA	NA	NA	0	0	27.718654	27.718654	NA	NA	NA	0	0	28.550213	28.550213	NA	NA	NA
7.3.2.1.	91.6	91.6	0	0	NA	NA	NA	22.341	22.341	0	0	NA	NA	8	82.164	82.164	0	0	NA	NA	2	0	0	3.7215444	3.7215444	NA	NA	NA	0	0	3.8331908	3.8331908	NA	NA	NA
7.3.2.2.	0	0	0	0	NA	NA	NA	9.9	9.9	0	0	NA	NA	2	53.715	53.715	0	0	NA	NA	4	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.2.3.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	263.26	263.26	0	0	NA	NA	50	270.10826	270.10826	0	0	NA	NA	79
7.3.2.4.	0	0	9.5	9.5	NA	NA	NA	0	0	11	11	NA	NA	NA	0	0	12.7	12.7	NA	NA	NA	0	0	13	13	NA	NA	NA	0	0	13.5	13.5	NA	NA	NA
7.3.2.5.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	11.5167	11.5167	NA	NA	NA	0	0	11.91978	11.91978	NA	NA	NA
7.3.2.6.	0	0	9.5	9.5	NA	NA	NA	0	0	11	11	NA	NA	NA	0	0	12.7	12.7	NA	NA	NA	0	0	13	13	NA	NA	NA	0	0	13.5	13.5	NA	NA	NA
7.3.3.1.	0	0	3.4	3.4	NA	NA	NA	0	0	9.02586	9.02586	NA	NA	NA	0	0	8.77493088	8.77493088	NA	NA	NA	0	0	8.9865747	8.9865747	NA	NA	NA	330.38013	330.38013	9.256172	9.256172	NA	NA	6
7.3.3.2.	0	0	25	25	NA	NA	NA	0	0	60.8219	60.8219	NA	NA	NA	0	0	59.1875392	59.1875392	NA	NA	NA	0	0	60.63743	60.63743	NA	NA	NA	0	0	62.456553	62.456553	NA	NA	NA
7.3.3.3.	173.7	173.7	0	0	0.52	0.52	NA	3057.09	3057.09	0	0	7.835	7.835	NA	6156.716	6156.716	0	0	12.3	12.3	NA	6570.3893	6570.3893	0	0	12.9	12.9	NA	6704.1539	6704.1539	0	0	12.9	12.9	NA
7.3.3.4.	0	0	22.3	22.3	NA	NA	NA	0	0	22.4565	22.4565	NA	NA	NA	0	0	29.396364	29.396364	NA	NA	NA	0	0	30.138143	30.138143	NA	NA	NA	0	0	31.042287	31.042287	NA	NA	NA
7.3.3.5.	0	0	39.1	39.1	NA	NA	NA	0	0	39.2988	39.2988	NA	NA	NA	0	0	51.443637	51.443637	NA	NA	NA	0	0	52.74175	52.74175	NA	NA	NA	0	0	54.324002	54.324002	NA	NA	NA
7.3.3.6.	436.9	436.9	0	0	NA	NA	NA	597.152	597.152	0	0	NA	NA	NA	569.41141	569.41141	0	0	NA	NA	NA	400	400	0	0	NA	NA	NA	822.27996	822.27996	0	0	NA	NA	NA
7.3.3.7.	898.7	898.7	0	0	NA	NA	283	3559.5	3559.5	0	0	NA	NA	1960	1486.59297	1486.59297	0	0	NA	NA	862	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.3.8.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	711.1	711.1	0	0	NA	NA	13
7.3.3.9.	412.5	412.5	0	0	NA	NA	NA	1253.25	1253.25	0	0	NA	NA	NA	3129.95	3129.95	0	0	NA	NA	NA	210	210	0	0	NA	NA	NA	654.1	654.1	0	0	NA	NA	3
7.3.3.10.	0	0	4.8	4.8	NA	NA	NA	0	0	12.7866	12.7866	NA	NA	NA	0	0	12.4311521	12.4311521	NA	NA	NA	0	0	12.730981	12.730981	NA	NA	NA	0	0	13.11291	13.11291	NA	NA	NA
7.3.3.11.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.3.12.	0	0	37.4	37.4	NA	NA	NA	669.712	669.712	97.9696	97.9696	NA	NA	NA	1674.57649	1674.57649	95.315287	95.315287	NA	NA	NA	0	0	97.621975	97.621975	NA	NA	NA	0	0	100.55063	100.55063	NA	NA	NA
7.3.3.13.	4841.8	4841.8	0	0	NA	NA	371	2419.42	2419.42	0	0	NA	NA	243	1727.52085	1727.52085	0	0	NA	NA	223	1216.16	1216.16	0	0	NA	NA	165	0	0	0	0	NA	NA	NA
7.3.3.14.	55.7	55.7	9.5	9.5	NA	NA	NA	308.497	308.497	5.57859	5.57859	NA	NA	NA	0	0	12.8276	12.8276	NA	NA	NA	70	70	13.32175	13.32175	NA	NA	NA	100	100	13.721403	13.721403	NA	NA	NA
7.3.3.15.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.3.16.	99.1	99.1	0	0	NA	NA	NA	165.546	165.546	0	0	NA	NA	NA	508.64898	508.64898	0	0	NA	NA	NA	75	75	0	0	NA	NA	NA	312.2	312.2	0	0	NA	NA	NA
7.3.3.17.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.1.	0	0	15	15	NA	NA	118.6	0	0	14.6725	14.6725	NA	NA	45.85	0	0	8.1778575	8.1778575	54.9	54.9	NA	0	0	8.4201932	8.4201932	29	29	NA	0	0	8.675889	8.675889	50	50	NA
7.3.4.2.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.3.	0	0	11.8	11.8	NA	NA	NA	0	0	20.4423	20.4423	NA	NA	NA	0	0	19.8701208	19.8701208	NA	NA	NA	130	130	20.391387	20.391387	NA	NA	NA	0	0	21.003129	21.003129	NA	NA	NA
7.3.4.4.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	53.3775	53.3775	211	211	NA	0	0	59.4	59.4	211	211	NA	0	0	59.4	59.4	211	211	NA
7.3.4.5.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.6.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	0	0	0	30.51231	30.51231	NA	NA	876	0	0	33	33	NA	NA	850	0	0	35	35	NA	NA	850
7.3.4.7.	0	0	0	0	211	211	NA	0	0	105.06	105.06	211	211	NA	0	0	59.56	59.56	211	211	NA	0	0	65	65	211	211	NA	0	0	66.5	66.5	211	211	NA
7.3.4.8.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.9.	0	0	0	0	211	211	NA	0	0	38.535	38.535	211	211		0	0	33.93	33.93	211	211	NA	0	0	40	40	211	211	NA	0	0	41.5	41.5	211	211	NA
7.3.4.10.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.11.	0	0	35.1	35.1	211	211	NA	0	0	34.2358	34.2358	211	211	NA	0	0	11.129822	11.129822	211	211	NA	0	0	19.654518	19.654518	211	211	NA	0	0	20.2	20.2	211	211	NA
7.3.4.12.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
7.3.4.13.	254.8	254.8	0	0	NA	NA	1588	127.338	127.338	0	0	NA	NA	191	90.92015	90.92015	0	0	NA	NA	557	64.0084	64.0084	0	0	NA	NA	241	65.92865	65.92865	0	0	NA	NA	225

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Asset inspection	Asset Management & Inspections	7.3.4.14.	Quality assurance / quality control of inspections	Equipment failure	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	11.8	11.8	NA	NA	NA	0	0	20.4423	20.4423	NA	NA	NA	0	0	19.8701208	19.8701208	NA	NA	NA	0	0	20.391387	20.391387	NA	NA	NA	0	0	21.003129	21.003129	NA	NA	NA
Asset inspection	Asset Management & Inspections	7.3.4.15.	Substation inspections	Equipment failure	Vandalism / Theft	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	30.8	30.8	NA	NA	NA	0	0	159.986	159.986	NA	NA	NA	0	0	170.756689	170.756689	NA	NA	NA	0	0	228.84134	228.84134	NA	NA	NA	0	0	235.70658	235.70658	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.1.	Additional efforts to manage community and environmental impacts	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	13.1	13.1	NA	NA	NA	0	0	22.7137	22.7137	NA	NA	NA	0	0	35.822016	35.822016	NA	NA	NA	0	0	38.407097	38.407097	NA	NA	NA	0	0	39.53681	39.53681	NA	NA	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.2.	Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment	Contact with vegetation	Equipment failure	2019	0.35	NA	NA	0.35	0.35	D.19-08-027	NA	Exceeding Compliance	GO-95	Increases vegetation clearances, criterial for tree removals, and eliminates overhang on sub-transmission. These are above the 2017 baseline vegetation clearances that were in effect before CPUC Decision 17-12-024 was adopted.	0	0	15	15	NA	NA	118.6	0	0	14.6725	14.6725	NA	NA	45.85	0	0	8.1778575	8.1778575	54.9	54.9	NA	0	0	8.4231932	8.4231932	29	29	NA	0	0	8.675889	8.675889	50	50	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.3.	Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.4.	Emergency response vegetation management due to red flag warning or other urgent weather conditions	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	36.1	36.1	NA	NA	NA	0	0	82.8261	82.8261	NA	NA	NA	0	0	117.630088	117.630088	NA	NA	NA	0	0	97.25	97.25	NA	NA	NA	0	0	100.16	100.16	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.5.	Fuel management (including all wood management) and management of "slash" from vegetation management activities	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	45.1	45.1	NA	NA	NA	0	0	103.533	103.533	NA	NA	NA	0	0	141.3109	141.3109	NA	NA	NA	0	0	115	115	NA	NA	NA	0	0	118.45	118.45	NA	NA	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.6.	Improvement of inspections	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	2936	29.6	NA	NA	NA	0	0	22.7137	22.7137	NA	NA	NA	0	0	38.5708368	38.5708368	NA	NA	2	130	130	41.557097	41.557097	NA	NA	4	0	0	42.77681	42.77681	NA	NA	4
Vegetation inspection	Vegetation Management & Inspections	7.3.5.7.	Remote sensing inspections of vegetation around distribution electric lines and equipment	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	0	0	211	211	NA	0	0	105.06	105.06	211	211	NA	0	0	59.56	59.56	211	211	NA	0	0	65	65	211	211	NA	0	0	66.5	66.5	211	211	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.8.	Remote sensing inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.9.	Other discretionary inspections of vegetation around distribution electric lines and equipment	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	BVES will be contracting for UAV HD Imagery in 2021	0	0	0	0	211	211	NA	0	0	38.535	38.535	211	211		0	0	15.93	15.93	211	211	NA	0	0	40	40	211	211	NA	0	0	41.5	41.5	211	211	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.10.	Other discretionary inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.11.	Patrol inspections of vegetation around distribution electric lines and equipment	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Bear Valley Electric Service's patrol inspections of vegetation around distribution electric lines and equipment are fully captured in Detailed inspection of vegetation around distribution electric lines and equipment and Patrol inspections of distribution electric lines and equipment.	0	0	35.09345	35.09345	211	211	NA	0	0	34.2358	34.2358	211	211	NA	0	0	19.0816675	19.0816675	211	211	NA	0	0	19.654118	19.654118	211	211	NA	0	0	20.243741	20.243741	211	211	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.12.	Patrol inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Vegetation inspection	Vegetation Management & Inspections	7.3.5.13.	Quality assurance / quality control of vegetation management	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	19.69031	19.69031	NA	NA	45	0	0	34.0706	34.0706	NA	NA	31	0	0	56.023708	56.023708	NA	NA	112	0	0	60.235645	60.235645	NA	NA	72	0	0	62.005215	62.005215	NA	NA	72
Vegetation management project	Vegetation Management & Inspections	7.3.5.14.	Recruiting and training of vegetation management personnel	Contact with vegetation	Equipment failure	2020	0.58	NA	NA	0.58	0.58	GRC	WMP Memorandum Account	Exceeding Compliance	GO-95	Places a full-time contract utility forester as part of the BVES team. The job duties of the contract forester would include:	0	0	22.93292	22.93292	NA	NA	NA	0	0	15.8996	15.8996	NA	NA	NA	0	0	29.1986424	29.1986424	NA	NA	NA	0	0	31.609968	31.609968	NA	NA	NA	0	0	32.535767	32.535767	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.15.	Identification and remediation of "at-risk species"	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Remediation of at-risk species is a subset to the company's vegetation management practices to achieve clearances around electric lines and equipment as well as being outlined in the reoccuring training of vegetation managment personnel. As such, Bear Valley Electric Service does not have a specific wildfire mitigation initiative for remediation of at-risk species at this time.	0	0	45.12234	45.12234	NA	NA	NA	0	0	103.533	103.533	NA	NA	NA	0	0	150.473636	150.473636	NA	NA	NA	0	0	125.5	125.5	NA	NA	NA	0	0	129.25	129.25	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.16.	Removal and remediation of trees with strike potential to electric lines and equipment	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Removal and remediation of trees with strike potential to electric lines and equipment is a subset to the company's vegetation management practices to achieve clearances around electric lines and equipment as described in reoccuring training of vegetation management personnel. As such, Bear Valley Electric Service does not have a specific wildfire mitigation initiative for removal and remediation of trees with strike potential at this time.	0	0	49.63458	49.63458	NA	NA	123	0	0	113.886	113.886	NA	NA	128	0	0	164.604725	164.604725	NA	NA	157	0	0	137	137	NA	NA	88	0	0	141.095	141.095	NA	NA	88
Vegetation inspection	Vegetation Management & Inspections	7.3.5.17.	Substation inspection	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Substation vegetation management is a subset to the company's overall vegetation management initiatives as described in Vegetation Management	0	0	1.61975	1.61975	NA	NA	144	0	0	6.42946	6.42946	NA	NA	144	0	0	5.050656	5.050656	NA	NA	144	0	0	5.2021757	5.2021757	NA	NA	144	0	0	5.358241	5.358241	NA	NA	144
Vegetation management project	Vegetation Management & Inspections	7.3.5.18.	Substation vegetation management	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Substation inspections are a subset to the company's overall vegetation management inspections as described in Detailed Inspection of vegetation around distribution e;ectric lines and equipemnt, and Recruitting and training of vegetation management personnel	0	0	3.32074	3.32074	NA	NA	NA	0	0	9.41	9.41	NA	NA	NA	0	0	17.34083	17.34083	NA	NA	NA	0	0	17.861055	17.861055	NA	NA	NA	0	0	18.396887	18.396887	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.19.	Vegetation management enterprise system	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	63.17128	63.17128	NA	NA	NA	0	0	144.946	144.946	NA	NA	NA	0	0	206.997995	206.997995	NA	NA	NA	0	0	171.5	171.5	NA	NA	NA	0	0	176.63	176.63	NA	NA	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.20.	Vegetation management to achieve clearances around electric lines and equipment	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Vegetation management to achieve clearances around electric lines and equipment is captured in Detailed Inspection of vegetation around distribution electric lines and equipemnt, and Recruitting and training of vegetation management personnel	0	0	676.8351	676.8351	NA	NA	NA	0	0	1552.99	1552.99	NA	NA	NA	0	0	2119.66349	2119.66349	NA	NA	NA	0	0	1725	1725	72	72	NA	0	0	1776.75	1776.75	72	72	NA
Vegetation management project	Vegetation Management & Inspections	7.3.5.21.	Vegetation management activities post-fire	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.1.	Automatic recloser operations	Other contact with object	Equipment failure	2019	0.41	NA	NA	0.41	0.41	D.19-08-027	GRC	In Compliance	NA		0	0	11.81419	11.81419	NA	NA	NA	0	0	20.4423	20.4423	NA	NA	NA	0	0	19.8701208	19.8701208	NA	NA	NA	0	0	20.391387	20.391387	NA	NA	NA	0	0	21.003129	21.003129	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.2.	Protective equipment and device settings	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	12.461403	12.461403	NA	NA	NA	0	0	12.835245	12.835245	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.3.	Crew-accompanying ignition prevention and suppression resources and services	Other contact with object	Equipment failure	2019	2.23	NA	NA	2.23	2.23	D.19-08-027	GRC	In Compliance	NA	Bear Valley Electric Service does not currently deploy crew-accompanying ignition prevention and suppression resources and services as part of its routine operational practices. When an emergency occurs, BVES communicates and collaborates with local emergency response teams, which can include crew-accompanying ignition prevention and suppression resources and services. Additionally, during elevated risk conditions or during fire season, BVES leverages specific work practices and protocols and makes available specific resources and tools for use by operations personnel as included in Grid Operation and Protocols. However, BVES does not currently have a specific grid operations and protocols wildfire mitigation initiative focused on crew-accompanying ignition prevention and suppression resources and services. The use of these services will be re-evaluated and considered for future incorporation as part of the annual WMP review process.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.4.	Personnel work procedures and training in conditions of elevated fire risk	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Wildfire Infrastructure Protection Teams. Roles and responsibilities for staff to respond to protect system infrastructure in case of emergencies.	0	0	4.594406	4.594406	NA	NA	NA	0	0	7.9498	7.9498	NA	NA	NA	0	0	7.7272692	7.7272692	NA	NA	NA	0	0	7.9299839	7.9299839	NA	NA	NA	0	0	8.1678835	8.1678835	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.5.	Protocols for PSPS re-energization	Other contact with object	Equipment failure	2019	5.26	NA	NA	5.26	5.26	D.19-08-027	GRC and Fire Hazard Prevt. Memorandum Account	In Compliance	R. 18-12-005	Bear Valley Electric Service considers re-energization after a PSPS event to be a subset of outage restoration and re-energization protocols generally included in Grid Operations and Protocol. Therefore, the BVES does not have a separate protocol for PSPS.	0	0	4.725675	4.725675	NA	NA	NA	0	0	8.17694	8.17694	NA	NA	NA	0	0	7.94806832	7.94806832	NA	NA	NA	0	0	28.156555	28.156555	NA	NA	NA	0	0	29.001252	29.001252	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.6.	PSPS events and mitigation of PSPS impacts	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	PSPS Protocols. Protocols and procedures to respond to and recover from de-energization events, which proactively prevent wildfires. Costs partially recovered. RSE is an estimate based on latest risk assessment.	0	0	4.515645	4.515645	NA	NA	NA	0	0	7.81352	7.81352	NA	NA	NA	0	0	7.59480175	7.59480175	NA	NA	NA	0	0	7.7940414	7.7940414	NA	NA	NA	0	0	8.0278626	8.0278626	NA	NA	NA
Other	Grid Operations & Operating Protocols	7.3.6.7	Stationed and on-call ignition prevention and suppression resources and services	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Other	Data Governance	7.3.7.1.	Centralized repository for data	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	D. 19-08-027	GRC	In Compliance	NA	GIS Data Collection & Sharing. Maintain and share Geographic Information System (GIS) database on system infrastructure for asset management and planning with key stakeholders.	0	0	24.86387	24.86387	NA	NA	NA	0	0	191.777	191.777	NA	NA	NA	0	0	225.5478	225.5478			0	0	0	101.27564	101.27564	NA	NA	NA	0	0	84.762907	84.762907	NA	NA	NA
Other	Data Governance	7.3.7.2.	Collaborative research on utility ignition and/or wildfire	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Other	Data Governance	7.3.7.3.	Documentation and disclosure of wildfire-related data and algorithms	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	4.856944	4.856944	NA	NA	NA	0	0	8.40407	8.40407	NA	NA	NA	0	0	8.16882744	8.16882744	NA	NA	NA	0	0	8.3831259	8.3831259	NA	NA	NA	0	0	8.6348197	8.6348197	NA	NA	NA
Other	Data Governance	7.3.7.4.	Tracking and analysis of near miss data	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	4.2006	4.2006	NA	NA	NA	0	0	7.26839	7.26839	NA	NA	NA	0	0	7.06493184	7.06493184	NA	NA	NA	0	0	7.250271	7.250271	NA	NA	NA	0	0	7.4677792	7.4677792	NA	NA	NA
Other	Resource Allocation Methodology	7.3.8.1.	Allocation methodology development and application	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	4.594406	4.594406	NA	NA	NA	0	0	7.9498	7.9498	NA	NA	NA	0	0	7.7272692	7.7272692	NA	NA	NA	0	0	7.9299839	7.9299839	NA	NA	NA	0	0	8.1678835	8.1678835	NA	NA	NA
Other	Resource Allocation Methodology	7.3.8.2.	Risk reduction scenario development and analysis	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	4.856944	4.856944	NA	NA	NA	0	0	8.40407	8.40407	NA	NA	NA	0	0	19.5973989	19.5973989	NA	NA	NA	0	0	29.757793	29.757793	NA	NA	NA	0	0	30.650526	30.650526	NA	NA	NA
Other	Resource Allocation Methodology	7.3.8.3.	Risk spend efficiency analysis	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	4.856944	4.856944	NA	NA	NA	0	0	8.40407	8.40407	NA	NA	NA	0	0	19.5973989	19.5973989	NA	NA	NA	0	0	29.757793	29.757793	NA	NA	NA	0	0	30.650526	30.650526	NA	NA	NA
Other	Emergency Planning & Preparedness	7.3.9.1.	Adequate and trained workforce for service restoration	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	GRC	In Compliance	GO 166		0	0	6.082339	6.082339	NA	NA	NA	0	0	7.24382	7.24382	NA	NA	NA	0	0	7.84512614	7.84512614	NA	NA	NA	0	0	8.0568389	8.0568389	NA	NA	NA	0	0	8.2985441	8.2985441	NA	NA	NA
Other	Emergency Planning & Preparedness	7.3.9.2.	Community outreach, public awareness, and communications efforts	Other contact with object	Equipment failure	NA	NA	NA	NA	NA	NA	NA	GRC	In Compliance	GO 167		0	0	0	0	NA	NA	NA	0	0	9.00866	9.00866	NA	NA	NA	0	0	79.20476	79.20476	NA	NA	422	0	0	81.580903	81.580903	NA	NA	360	0	0	84.02833	84.02833	NA	NA	360
Other	Emergency Planning & Preparedness	7.3.9.3.	Customer support in emergencies	Contact with vegetation	Equipment failure	NA	NA	NA	NA	NA	NA	NA	GRC	In Compliance	R. 18-12-005	BVES will be enhancing its communications and notification plans across multiple customer groups and stakeholder continuing in 2022	0	0	0	0	NA	NA	NA	0	0	2.88509	2.88509	NA	NA	NA	0	0	60.17811	60.17811	NA	NA	NA	0	0	61.983453	61.983453	NA	NA	NA	0	0	63.842957	63.842957	NA	NA	NA
Other	Emergency Planning & Preparedness	7.3.9.4.	Disaster and emergency preparedness plan	Other contact with object	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	D. 19-08-027	NA	In Compliance	GO 166	Emergency Reporting & Procedures. Protocols and procedures for staff to respond to faults, emergencies, outages, disaster events (such as earthquakes, wildfire, etc.), etc.	0	0	4.226854	4.226854	NA	NA	NA	0	0	7.31382	7.31382	NA	NA	NA	0	0	7.10908766	7.10908766	NA	NA	NA	0	0	7.2955852	7.2955852	NA	NA	NA	0	0	7.5144528	7.5144528	NA	NA	NA
Other	Emergency Planning & Preparedness	7.3.9.5.	Preparedness and planning for service restoration	Contact with vegetation	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	D. 19-08-027	CEMA, if applicable	In Compliance	GO 166	Post-Incident Recovery, Restoration & Remediation. Protocols and procedures to respond to and recover from any wildfire or related emergency events.	0	0	4.043077	4.043077	NA	NA	NA	0	0	6.99582	6.99582	NA	NA	NA	0	0	6.7999969	6.7999969	NA	NA	NA	0	0	6.9783859	6.9783859	NA	NA	NA	0	0	7.1877374	7.1877374	NA	NA	NA
Other	Emergency Planning & Preparedness	7.3.9.6.	Protocols in place to learn from wildfire events	Contact with vegetation	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA		0	0	3.99057	3.99057	NA	NA	NA	0	0	6.90497	6.90497	NA	NA	NA	0	0	6.71168525	6.71168525	NA	NA	NA	0	0	6.8877575	6.8877575	NA	NA	NA	0	0	7.0943902	7.0943902	NA	NA	NA
Other	Stakeholder Cooperation & Community Engagement	7.3.10.1	Community engagement	Contact with vegetation	Wire-to-wire contact	NA	0	NA	NA	0	0	NA	NA	In Compliance	NA	BVES will be enhancing its communications and notification plans across multiple customer groups and stakeholder continuing in 2022	0	0	23.27607	23.27607	NA	NA	NA	0	0	29.8836	29.8836	NA	NA	NA	0	0	29.9051376	29.9051376	NA	NA	NA	0	0	30.735785	30.735785	NA	NA	NA	0	0	31.657859	31.657859	NA	NA	NA
Other	Stakeholder Cooperation & Community Engagement	7.3.10.2	Cooperation and best practice sharing with agencies outside CA	Contact with vegetation	Wire-to-wire contact	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	This is a System Wide Initiative that targets all ignition probability drivers. As a System Wide Initiative, this initiative does not have a specified risk reduction or a risk spend efficiency. BVES' effort reduces the risk of escalation through support of accelerated restoration.	0	0	9.976425	9.976425	NA	NA	NA	0	0	17.2624	17.2624	NA	NA	NA	0	0	16.7793135	16.7793135	NA	NA	NA	0	0	17.219394	17.219394	NA	NA	NA	0	0	17.735976	17.735976	NA	NA	NA
Other	Stakeholder Cooperation & Community Engagement	7.3.10.3	Cooperation with suppression agencies	Contact with vegetation	Wire-to-wire contact	NA	0	NA	NA	0	0	NA	NA	In Compliance	NA		0	0	4.2006	4.2006	NA	NA	NA	0	0	7.26839	7.26839	NA	NA	NA	0	0	7.06493184	7.06493184	NA	NA	NA	0	0	7.250271	7.250271	NA	NA	NA	0	0	7.4677792	7.4677792	NA	NA	NA
Other	Stakeholder Cooperation & Community Engagement	7.3.10.4	Forest service and fuel reduction cooperation and joint roadmap	Contact with vegetation	Wire-to-wire contact	2021	0	NA	NA	0	0	NA	NA	In Compliance	NA	While collaboration such as this is critical to the overall reduction of wildfire risk in the state of CA, Bear Valley Electric Service does not have program dedicated to cooperation with the forest service and fuel reduction and the development of a joint roadmap specific to this Wildfire Mitigation Plan. BVES views these efforts on an as-needed basis and incorporates additional efforts to manage community environments within other programs, such as those included in the company's overall vegetation management and inspections programs.	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	11.9131568	11.9131568	NA	NA	NA	0	0	13.65	13.65	NA	NA	NA	0	0	14.04	14.04	NA	NA	NA
Grid hardening	Situational Awareness & Forecasting	7.3.2.2.2	Continuous monitoring sensors	Equipment failure	Contact with vegetation	2022	15.279	NA	NA	15.279	15.279	NA	NA	NA	NA	Added sub initiative - Online Diagnostic System Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	75	75	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.3	Covered conductor installation	Contact with vegetation	Wire-to-wire contact	2019	0.21	NA	NA	0.21	0.21	NA	WMP Memorandum Account	NA	NA	Added sub initiative	21.90562	21.90562	0	0	0	0	0	13.7135	13.7135	0	0	0	0	0	39.47868	39.47868	0	0	0	0	0	1235.9873	1235.9873	0	0	2.7	2.7	0	0	0	0	0	NA	NA	NA

Grid hardening	Grid Design & System Hardening	7.3.3.6.2	Distribution pole replacement and reinforcement, including with composite poles	Equipment failure	Wire-to-wire contact	2019	0.21	NA	NA	0.21	0.021	NA	WMP Memorandum Account	NA	GO 95	Added sub initiative	77.66536	77.66536	0	0	NA	NA	NA	48.6205	48.6205	0	0	NA	NA	NA	139.97412	139.97412	0	0	NA	NA	NA	4382.1367	4382.1367	0	0	NA	NA	70	0	0	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.6.3	Distribution pole replacement and reinforcement, including with composite poles	Equipment failure	Wire-to-wire contact	2020	0.15	NA	NA	0.15	0.15	NA	WMP Memorandum Account	NA	NA	Added sub initiative	0	0	0	0	NA	NA	NA	11.02	11.02	0	0	NA	NA	5	16.08112	16.08112	0	0	NA	NA	5	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.6.4	Distribution pole replacement and reinforcement, including with composite poles	Equipment failure	Wire-to-wire contact	2021	0.15	NA	NA	0.15	0.15	NA	WMP Memorandum Account	NA	NA	Added sub initiative	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	560.07165	560.07165	0	0	NA	NA	400	576.8	576.8	0	0	NA	NA	412	816.2	816.2	0	0	NA	NA	500
Grid hardening	Grid Design & System Hardening	7.3.3.9.2	Installation of system automation equipment	Equipment failure	Wire-to-wire contact	2019	1.18	NA	NA	1.18	1.18	GRC	NA	In Compliance	NA	Added sub initiative	2691.19	2691.19	0	0	NA	NA	NA	16.1457	16.1457	0	0	NA	NA	NA	189.51247	189.51247	0	0	NA	NA	NA	123.608	123.608	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.9.3	Installation of system automation equipment	Equipment failure	Wire-to-wire contact	2019	1.18	NA	NA	1.18	1.18	GRC	NA	In Compliance	NA	Added sub initiative	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	197.6	197.6	0	0	NA	NA	10
Grid hardening	Grid Design & System Hardening	7.3.3.9.4	Installation of system automation equipment	Equipment failure	Wire-to-wire contact	2023	9.04	NA	NA	9.04	9.04	NA	NA	NA	NA	Added sub initiative - Server Room Upgrade	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	126.7	126.7	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.11.2	Mitigation of impact on customers and other residents affected during PSPS event	PSPS - for sectionalization, etc.	Equipment failure	2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	Added sub initiative	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	561.5	561.5	0	0	NA	NA	NA
Grid hardening	Grid Design & System Hardening	7.3.3.12.2	Other corrective action	Other contact with object	Equipment failure	2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	Added sub initiative	701.348	701.348	0	0	NA	NA	NA	1453.22	1453.22	0	0	NA	NA	214	274.188	274.188	0	0	NA	NA	74	661.806	661.806	0	0	NA	NA	80	605.6116	605.6116	0	0	NA	NA	100
Grid hardening	Asset Management & Inspections	7.3.4.9.2	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Equipment failure	Wire-to-wire contact	2021	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Added sub initiative	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	53.3775	53.3775	211	211	NA	0	0	59.4	59.4	211	211	NA	0	0	59.4	59.4	211	211	NA
Grid hardening	Vegetation Management & Inspections	7.3.5.9.2	Other discretionary inspections of vegetation around distribution electric lines and equipment	Contact with vegetation	Other contact with object	NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	Added sub initiative	0	0	0	0	NA	NA	NA	0	0	0	0	NA	NA	NA	0	0	53.3775	53.3775	211	211	NA	0	0	59.4	59.4	211	211	NA	0	0	59.4	59.4	211	211	NA

APPENDIX E. BVES VEGETATION MANAGEMENT AND VEGETATION MANAGEMENT QC PROGRAMS POLICY AND PROCEDURE

Bear Valley Electric Service, Inc.
Vegetation Management
and
Vegetation QA/QC Programs

October 6, 2021

Paul President BVES Inc

Digitally signed by Paul Marconi, President
Date: 2021.10.06 -07'00'

Approved by: ______________________________

Paul Marconi, President, Treasurer, & Secretary

Purpose: Provide requirements for the Vegetation Management (VM) program and VM quality assurance (QA)/quality control (QC) program at Bear Valley Electric Service, Inc. (BVES).

Background: Proper clearance of vegetation around high voltage power lines is essential to public safety and ensuring the transmission and distribution (T&D) system is reliable. BVES has established vegetation clearance standards to achieve safe and reliable T&D operations, which are described in Section 3. Efficient, effective, and sustained implementation of the standards is the objective of the VM program described in Section 4. Violation of BVES's vegetation clearance standards significantly increases the risk of ignitions and; therefore, utility caused wildfires when combined with dry weather conditions and high winds. Additionally, such violations increase the probability of vegetation caused outages.

BVES utilizes contractors to provide vegetation clearance services to maintain clearance standards. Ensuring that vegetation clearance operations are actually being performed to the desired standards is an essential element of mitigating the risk of ignition and outages. Therefore, BVES established a VM QA/QC program. The VM QA program is focused on providing confidence that quality requirements will be fulfilled. The VM QC program requires that certain designated BVES Staff perform VM QC checks on a frequent basis. The results of the VM QA/QC programs are essential to alerting BVES to the state of its VM program, which is a critical element for public safety. Section 5 provides guidance on the VM QA/QC program. Having assurance that vegetation clearance efforts are meeting our standards is essential to ensuring public safety from utility caused wildfires. It is critical that if there are problems in vegetation clearance, that BVES is aware of the problems and is able to then dedicate the proper resources toward vegetation clearance efforts to make it effective and resolve any problem areas.

Effective vegetation management requires specialized subject matter expertise; therefore, BVES at times may engage forester consulting services. Some of the duties that may be assigned to the forester include: inspections, auditing, customer contacts and issue resolution, work plans development, specialized projects, contractor safety observations, and vegetation management program documentation and data analysis.

Vegetation Clearance Standards: California Public Utilities Commission (CPUC) General Order 95 (GO-95), Rules for Overhead Electric Line Construction, Rule 35 Vegetation Management and Appendix E Guidelines to Rule 35 (trimming guidelines) provides minimum vegetation clearance standards applicable to BVES's T&D system.

For reference, BVES' Service Area is entirely within a "High Fire-Threat District" with areas classified as Zone 1 and Tiers 2 and 3 per Rule 21.1 of GO-95. Based upon GO-95 requirements (48 inches minimum radial clearance) and on the local climate, likelihood of icing conditions, tree limbs and branches subject to weakening due to high winds and snow weight, elevation, local conditions and access to vegetation for trimming, and species growth rates and characteristics, **the minimum allowable radial clearance of bare line conductors from**

vegetation is 72 inches in the BVES service area.

BVES has established the following requirements to safe clearance along bare line conductors is maintained throughout the BVES service area during the entire length of the vegetation management program cycle:

Radial Clearances: Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

Vegetation that is outside the minimum 72-inch safe clearance distance but is expected, taking into account vegetation species and growth rates and characteristics, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years) will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

Anytime it is determined that trimming of vegetation is necessary, BVES's contractor shall trim to least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

Blue Sky Requirement: No vertical coverage shall be allowed above BVES sub-transmission lines (34.5 kV).

Fast Growing Trees: All fast growing trees, (poplar, aspen, cottonwood…) will be trimmed to at least 12 feet and removal will be considered. BVES's contractor may determine that additional clearance would be prudent based on growth factors, wind, ice, etc.

Drip Line: All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

Tree Trunk and Major Limb Exception: Per Section 3.3 below and Appendix A, Trees and Major Limbs in Close Proximity to Bare Conductors, flow chart.

<u>Tree Removal</u>: Trees that are dead, rotten or diseased or dead, rotten or diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines, said trees or portions thereof should be removed. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines).

<u>Base of Poles/Structures</u>: For poles or structures that have non-exempt equipment per CALFIRE requirements, all flammable material and vegetation in a 10-foot radius around the base of the pole or structure shall be cut down and removed during each normal vegetation management cycle clearance visit. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.

<u>Right of Way</u>: All brush, limbs and foliage in the right of way (ROW) shall be cut up to 8-feet above the ground. All dead, dying, diseased or dried vegetation from 8 feet above the ground to the top of the power lines must be cut down during each normal vegetation management cycle clearance visit. This requirement is applicable to all ROWs in the HFTD Tier 3 and to all ROWs in the HFTD Tier 2 designated as having high strike potential by the Wildfire Mitigation & Safety Engineer. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.

<u>Tree Trunk and Major Limb Exception</u>. Appendix A, Trees and Major Limbs in Close Proximity to Bare Conductors, provides the information in this section in flowchart format. If a mature tree whose trunk or major limb is within 48 inches of bare conductors, take the following action:

If the tree or major limb is within 12 inches of the bare conductors regardless of thickness at conductor level, this is a Level 1 discrepancy and shall be immediately remediated by:

Removing the tree or limb immediately, or

Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If the tree or major limb is less than 6 inches thick at conductor level, then the tree or major limb must be trimmed or removed to achieve 72 inches clearance from bare conductors as follows:

If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is greater than 48 inches, then this is a Level 2 discrepancy and shall be corrected within 12 months.

If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is less than 48 inches but greater than 18 inches, then this is a Level 2 discrepancy and shall be corrected within 180 days. A tree guard should be installed as soon as operationally possible.

If there are burn marks or evidence of the tree or limb making contact with bare conductors and/or the clearance is less than 18 inches, then this is a Level 1 discrepancy and shall be immediately remediated by:

Removing the tree or limb immediately, or
Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If the tree or major limb is greater than 6 inches thick at conductor level and greater than 12 inches from bare conductors, then the tree or major limb shall be evaluated to determine if an exemption per GO-95 Rule 35 may be applied. Take the following action:

If there are burn marks present on the tree or major limb or evidence of the tree or limb making contact with the bare conductor, this is a Level 1 discrepancy and shall be immediately remediated by:

Removing the tree or major limb immediately, or
Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If there are no burn marks present on the tree or major limb and no evidence of the tree or limb making contact with the bare conductor, then the tree or major limb may be exempted provided the following:

Tree has been established in its current location for at least 10 years.
Tree trunk has a diameter at breast height (DBH) of at least 10”.
Tree or limb at the conductor level is at least 6” in diameter.
Tree is not re-sprouting at conductor level during the time of inspection.
Tree is healthy and not otherwise hazardous.
Tree is not easily climbable. Note the tree clearance crew can remove branches to render a tree not easily climbable.

If the tree cannot satisfy one or more of the above criteria (Section 3.3.3.2), then the tree or major limb must be removed. It should be designated as a Level 2 discrepancy and shall be corrected within 12 months.
If the tree satisfies all of the above criteria (Section 3.3.3.2), then the tree may be exempted and remain in place. The tree shall be:

Documented on Major Woody Stem Form and approved by the Wildfire Mitigation & Reliability Engineer.

Tracked in the Company's GIS applications for vegetation management.
Re-evaluated each year.
As a precaution, install a tree guard when operationally feasible.

Vegetation Management Program: The VM program is designed to ensure the standards described in Section 3 are achieved and sustained throughout the BVES service area.

Wildfire Mitigation & Reliability Engineer. The VM program shall be the responsibility of the Wildfire Mitigation & Reliability Engineer. Specifically, the Wildfire Mitigation & Reliability Engineer shall:

Establish and ensure BVES's vegetation clearance standards (Section 3) comply with state law, CPUC regulations and other higher authority requirements and achieve the desired public safety and reliability goals of the program given the local environmental conditions of the BVES service area.
Recommend to the President any changes to the BVES vegetation clearance standards (Section 3) that may be required due to:

Changes in the law, CPUC regulations, other higher authority requirements, and
Changes in the local service area environment (for example, extended draught conditions, tree pest infestations, etc.) that may warrant a change in clearance standards.

Ensure BVES applies sufficient resources to maintain the BVES vegetation clearance standards (Section 3) throughout the service area.
Recommend to the Utility Manager changes to vegetation management resources as appropriate to maintain compliance with the BVES vegetation clearance standards (Section 3).
Manage all aspects of vegetation management contracts in accordance with BVES's procurement policy. This shall include drafting requests for proposals (RFPs) as applicable, assisting in selecting contractors via the BVES bidding process, reviewing and approving invoices for the Utility Manager or President approval as applicable.
Perform the duties of the BVES Authorized Representative for vegetation management contracts and ensure the contractor is performing in accordance with the contract requirements.
Ensure contractor employees conducting vegetation clearance work are properly trained and certified as required by state law.
Coordinate with contractors and Field Operations to cover power lines or de-energize lines as needed.
Inform Field Operations Supervisor and Customer Program Specialist where vegetation clearance operations will be conducted each week.
Work with the Customer Program Specialist to generate or update customer outreach to educate customers on vegetation management efforts in the BVES service area.
Work with the Customer Service Supervisor or applicable Customer Service staff to resolve

customer inquiries or disputes involving vegetation clearance efforts.

Coordinate with the City of Big Bear Lake, County of San Bernardino, U.S. Forest Service, CALFIRE, Big Bear Fire Department, and other applicable stakeholders in the area of vegetation clearance efforts.

Coordinate with the City of Big Bear Lake, County of San Bernardino, U.S. Forest Service, CALFIRE, Big Bear Fire Department, and other applicable stakeholders in the area of fuels management efforts by the community.

Manage all aspects of the VM QA/QC program as described in Section 5.

Work closely with the GIS Specialist and contractors to ensure the vegetation clearance efforts are properly documented in the GIS and associated applications.

Work closely with the GIS Specialist to develop overlays to support presentations and documents regarding the vegetation management program.

Manage and provide oversight of the Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc., while working closely with the Field Inspector to ensure line inspection programs such as GO-165 Detailed Inspections and GO-165 Patrols are being conducted in compliance with CPUC regulations and BVES requirements and vegetation clearance discrepancies are being identified by the inspections.

Manage and provide oversight of the Forester's work activities when assigned. Some of the duties that may be assigned to the Forester include: inspections, auditing, customer contacts and issue resolution, work plans development, specialized projects, contractor safety observations, and vegetation management program documentation and data analysis.

Issues or causes to be issued vegetation orders to the contractor.

Review the results of line inspection programs such as GO-165 Detailed Inspections, GO- 165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. and ensuring any vegetation discrepancies are tracked and resolved. This is normally done by issuing or causing to be issued vegetation orders to the contractor.

Discrepancies of a significant safety nature that would be classified as Level 1 per GO-95 Rule 18 should be resolved immediately by notifying the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue.

Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

Other vegetation discrepancies of an urgent nature (Level 2) but do not rise to the Level 1 classification should be assigned to the contractor as a vegetation order with requirement to resolve within 30-days. Examples of Level 2 vegetation discrepancies are vegetation within 48 inches of high voltage lines, vegetation causing strain or abrasion on low voltage conductor, tree or portions of tree that are dead, rotten or diseased that may fall into power lines, etc. Non-urgent vegetation discrepancies should be tracked as Level 3 discrepancies and resolved by the contractor during the normal vegetation cycle.

Support the preparation of regulatory reports, General Rate Case testimony, Wildfire Mitigation Plan updates, Data Requests and other regulatory requests regarding vegetation management issues.
Support CPUC audits, Office Infrastructure Safety (OEIS) site visits, and other authorized agency reviews of vegetation management.

Utility Manager**.** Provides oversight of the VM and VM QA/QC programs. Specifically:

Reviews reports and directs changes to the program as deemed necessary. Keeps the President informed of such changes.
Ensures the VM program is properly resourced. Prepares annual O&M budget for vegetation management efforts.
Responsible for ensuring vegetation contracts are in place and managed per the BVES procurement policy.
Responsible for preparing regulatory reports, General Rate Case testimony, Wildfire Mitigation Plan updates, Data Requests responses and other regulatory requests regarding vegetation management issues. These should all be forwarded to the Regulatory Affairs Manager and the President prior to issuing.
Provides oversight of the VM QA/QC programs described in Section 5.
Responsible for supporting CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management.

Utility Engineer & Wildfire Mitigation Supervisor**.** Provides oversight of the Wildfire Mitigation & Reliability Engineer in managing the VM and VM QA/QC programs. Specifically:

Responsible for ensuring VM QA annual audit and quarterly vegetation management assessments are timely, complete, and accurate in accordance with Section 5.
Responsible for ensuring the Wildfire Mitigation & Reliability Engineer has adequate tools and staff support (GIS, Administrative, etc.) to properly manage the VM and VM QA/QC programs.
Responsible for reviewing vegetation requirements and ensuring the VM program is in compliance with requirements.
Responsible for ensuring VM program is executed per this procedure and BVES's current Wildfire Mitigation Plan.
Responsible for CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management. Coordinates closely with the Field Operations Supervisor on these matters and all communications with regulatory agencies through the Utility Manager and President.

Field Operations Supervisor**.** Provides support to the Wildfire Mitigation & Reliability Engineer in managing the VM and VM QA/QC programs. Specifically:

Provides support as needed to de-energize or cover lines as applicable and provides assistance in resolving vegetation discrepancies.

Closely supports the Utility Engineer & Wildfire Mitigation Supervisor on CPUC audits, OIES site visits, and other authorized agency reviews of vegetation management.
Ensures Field Inspector works closely with the Wildfire Mitigation & Reliability Engineer to achieve VM program requirements.

Field Inspector**.** Supports the Wildfire Mitigation & Reliability Engineer in the area of line inspections with regard to identifying, documenting, and tracking vegetation clearance discrepancies. Specifically:

Assists the Wildfire Mitigation & Safety Engineer to achieve VM program requirements.
Assists in ensuring line inspection programs such as GO-165 Detailed Inspections, GO- 165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. are being conducted in compliance with CPUC regulations and BVES requirements and vegetation clearance discrepancies are being identified by the inspections.
Assists in reviewing the results of line inspection programs such as GO-165 Detailed Inspections, GO-165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. and ensuring any vegetation discrepancies are tracked and resolved.
Assists in issuing or causing to be issued vegetation orders to the contractor.
Works closely in supporting CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management.

GIS Specialist**.** Supports the Wildfire Mitigation & Reliability Engineer in tracking vegetation clearance efforts and discrepancy management with the GIS and associated applications. Specifically:

Supports data entry and migration of contracted vegetation services and inspection programs into the GIS and associated applications.
Assists in scope of work development for RFPs regarding vegetation management service and inspection programs to ensure data and documentation requirements that are compatible with BVES GIS applications are accurately provided to bidders.
Assists in developing data reports and GIS overlays to support Management, OEIS, CPUC, CALFIRE, and other authorized agency reporting requirements.
Assists in developing overlays to support presentations and documents regarding the VM program.

Customer Service Supervisor**.** Works closely with the Wildfire Mitigation & Reliability Engineer on all customer issues regarding vegetation management. Specifically:

Coordinates responses to customer inquiries or disputes with the Wildfire Mitigation & Reliability Engineer.

Takes the lead on any customer complaints filed with the CPUC regarding vegetation management.

Supports customer outreach and education on vegetation management effort.

Ensures BVES Website and Social Media inform customers on where vegetation clearance work is being conducted on a weekly basis.

Customer Program Specialist**.** Supports the Wildfire Mitigation & Reliability Engineer on all customer outreach efforts. Specifically:

With input from the Wildfire Mitigation & Reliability Engineer, generates or updates customer outreach media products to educate customers on vegetation management efforts in the BVES service area.
BVES Website and Social Media inform customers on where vegetation clearance work is being conducted on a weekly basis.

Administrative Support Associate. Provides assistance in administering the VM program and VM QA/QC program. Specifically:

Provides administrative support as described in Section 5 for the VM QA/QC program.
Provides administrative support in the preparation and submission of reports and correspondence associated with the VM program.

Vegetation Quality Assurance/Quality Control Program:

Vegetation Management Quality Assurance Program. The VM QA program is the part of quality management focused on providing confidence that quality requirements will be fulfilled by the VM program. The confidence provided by quality assurance is twofold —internally to management and externally to customers, government agencies, regulators, certifiers, and other stakeholders. The VM QA program consists of the following elements:

Annual VM Program Audit conducted by the Forester if assigned (if not assigned, the Regulatory Compliance Project Engineer will perform the audit).
Quarterly VM Program Assessment conducted by the Wildfire Mitigation & Reliability Engineer.
Periodic VM QC checks conducted by staff per this policy and procedure.

Annual VM Program Audit. The Annual VM Program Audit will be conducted by the Forester (if not assigned, the Regulatory Compliance Project Engineer will perform the audit) in January each year covering the previous calendar year.

The audit is intended to be a comprehensive review of the VM Program covering at a minimum the areas and questions specified in Appendix B, VM Program Annual QA Audit Areas. The annual audit report shall be due each year by January 31 to the Wildfire Mitigation & Reliability Engineer.
The audit report shall be routed to the President, Utility Manager, Utility Engineer &

Wildfire Mitigation Supervisor, and the Field Operations Supervisor for review.
The Wildfire Mitigation & Reliability Engineer shall issue a report of corrective action on issues identified in the annual audit by May 1 each year if applicable.

Quarterly VM Program Assessment. The Quarterly VM Program Assessment is performed by the Wildfire Mitigation & Reliability Engineer according to the schedule in Table 5-1.

Table 5-1, Quarterly VM Assessment and Report Schedule

Period of Assessment and Report	Report Due Date
January 1 to March 31	April 15
April 1 to June 30	July 15
July 1 to September 30	October 15
October 1 to December 31	January 15

The Wildfire Mitigation & Reliability Engineer shall conduct the Quarterly VM Program Assessment and prepare a quarterly report on the VM Program to the President, Utility Manager, Utility Engineer & Wildfire Mitigation Supervisor, and the Field Operations Supervisor on the status of the program and its results. If assigned, the Forester shall assist in conducting the quarterly assessment and preparing the report.
5.3.2. The report shall include the following at a minimum:

Brief narrative on the status of the VM program, VM QC Checks program and analysis or commentary on the metrics below as applicable.
Number of trees trimmed as a result of the vegetation management program.
Number of trees removed as a result of the vegetation management program.
Number of Level 1 vegetation discrepancies identified.
Number of Level 1 vegetation discrepancies resolved.
Number of Vegetation Orders issued.
Number of Vegetation Orders resolved.
Any accidents, incidents, or near misses on the part of vegetation clearance personnel.
Number of outages where vegetation made contact with power lines and caused the outage (break out those outages where vegetation clearance was in violation of standards)
List of VM QC Checks performed (include name of evaluator and date performed).
List of significant findings from VM QC Checks.
Service area Map showing where contractor worked in the quarter and where contractor will work in the next quarter.
Where the contractor is in the vegetation cycle plan (e.g., percent complete).
Corrective action taken on issues noted in previous Quarterly VM Program Assessments.
Other items that would be useful to Management regarding vegetation management.

Vegetation Management Quality Control Check Program. The VM QC Check program is designed to check compliance with VM standards in the field. In particular, the program should check VM clearance contractor work. The Wildfire Mitigation & Reliability Engineer will administer the program.

Table 5-2, VM QC Check Periodicities, lists the designated staff that shall be assigned VM QC Checks and the periodicity for the checks.

Table 5-2: VM QC Check Periodicities

Title	Periodicity
President	Once every two months (January, March, May, July, September, November)
Utility Manager	Once every two months (February, April, June, August, October, December)
Utility Engineer & Wildfire Mitigation Supervisor	Once every two months (January, March, May, July, September, November)
Field Operations Supervisor	Once every two months (February, April, June, August, October, December)
Regulatory Compliance Project Engineer	Once every two months (January, March, May, July, September, November)
Wildfire Mitigation & Reliability Engineer	Twice per month
Field Inspector	Twice per month
Forester (if assigned)	Twice per month

The Administrative Support Associate shall assign VM QC Checks using the VM QC electronic tracking application.

Evaluators assigned to perform VM QC Checks will be provided a map of the assigned circuit area for the QC Check by the Administrative Support Associate and a copy of the Appendix C VM QC Check Form. These may be provided through the electronic tracking program if equipped. Additionally, the flowchart for Trees and Major Limbs in Close Proximity to Bare Conductors of Appendix A will be made available to evaluators.

Evaluators will inspect the designated circuit for compliance with the VM standards per Section 3 of this policy and procedure and document the results on the VM QC map in accordance with the instructions on the VM QC Check Form of Appendix C. The evaluator will annotate the completed VM QC map with the evaluator's name and date of the VM QC Check, sign the VM QC map, and route the VM QC map to the Wildfire Mitigation & Reliability Engineer. Additionally, the evaluator will update the VM QC Check Form of Appendix C – this may be done directly in the VM QC Check application if so equipped.

If an evaluator discovers a significant safety issue that would be classified as Level 1 per GO-95 Rule 18, the evaluator should immediately notify the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue. Additionally, notify the Wildfire Mitigation & Reliability Engineer as soon as practical. Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

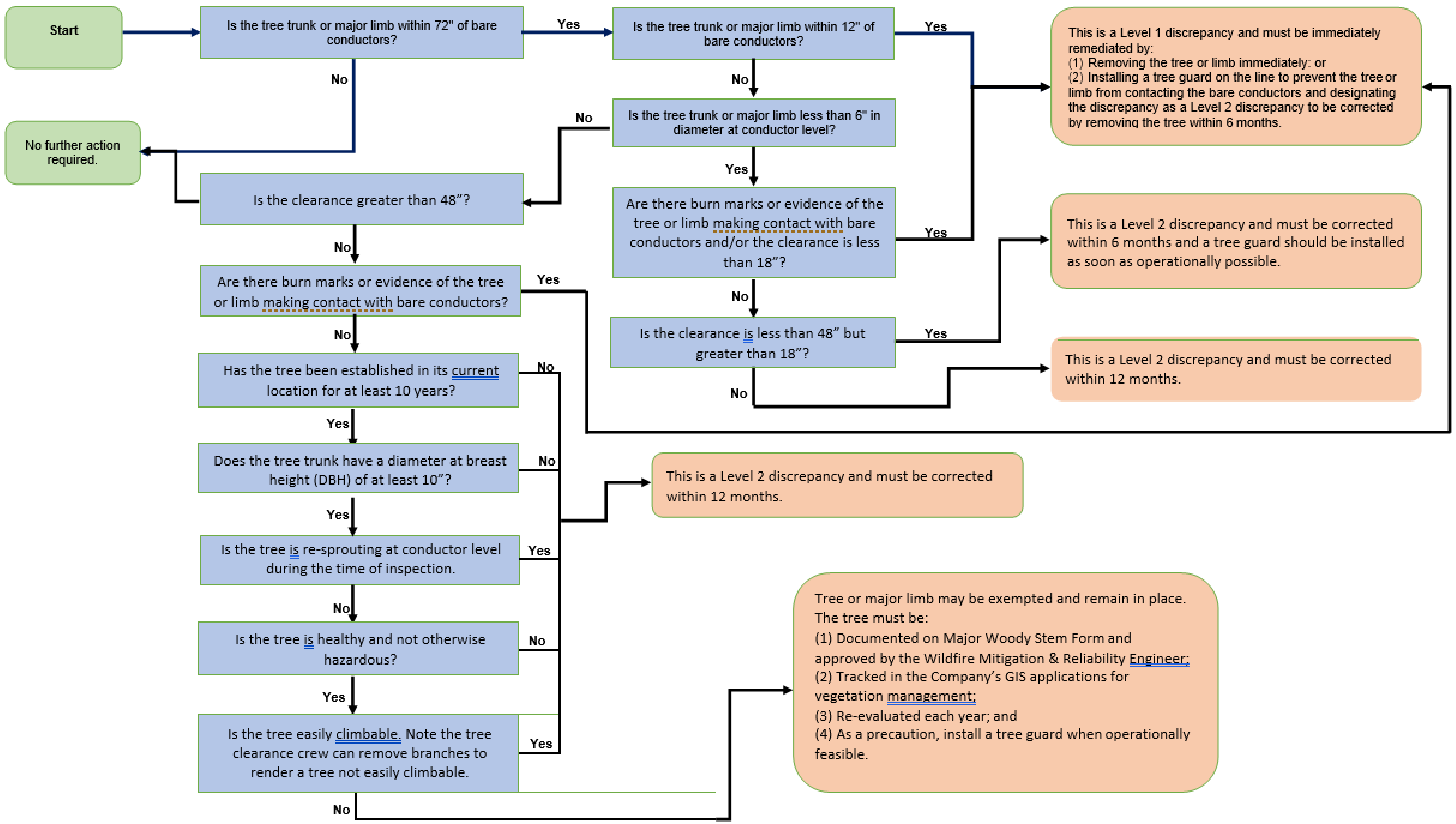
Completed VM QC Checks will be reviewed by the Wildfire Mitigation & Reliability Engineer. The Wildfire Mitigation & Reliability Engineer will issue vegetation orders as applicable to correct any discrepancies noted.

The Wildfire Mitigation & Reliability Engineer will also analyze the results of the VM QC Checks for trends and recommend corrective action to the Utility Manager if deemed necessary. This analysis shall be included in the Quarterly VM Program Assessment report.

The Administrative Support Associate shall check that assigned VM QC checks are being performed in a timely manner and send reminders to individuals alerting them if a VM QC check is overdue.

The VM QC electronic tracking application shall be used, if available, to maintain a record of the VM QC checks, track correction of vegetation orders, and perform program analysis.

Appendix A
Trees and Major Limbs in Close Proximity to Bare Conductors



Appendix B

VM Program Annual QA Audit Areas	
VM Line Clearance	Is the VM program effective at ensuring vegetation meets required clearance specifications?
	Is the VM program on track with the programmed schedule?
	Is the VM program effective in reducing vegetation contact with bare conductors?
	Are any changes to the VM clearance standards delineated in Section 3 necessary?
	Is the VM clearance contractor(s) executing work in accordance with the VM contract(s)?
	Are changes to the VM Contract Scope of Work needed?
VM Inspections	Are VM inspections (patrol, detailed, LiDAR, etc.) being conducted in accordance with the Company's effective Wildfire Mitigation Plan?
	Are the results of VM inspections being documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
	For each type of inspection performed, assess whether or not the inspection is effective and useful to assisting in achieving VM program objectives?
	Should additional inspections be performed?
	Is the scheduling of inspections appropriate or should the schedule be modified?
VM QC Checks	Are VM QC Checks being performed in accordance with the requirements of this policy and procedure (Section 5.3)?
	Are personnel performing VM QC Checks sufficiently knowledgeable and qualified to perform the checks?
	Are VM QC Checks documented?
	Are discrepancies identified in VM QC checks being tracked and resolved in a timely manner in accordance with GO-95 Rule 18?
	Are VM QC Checks effective at identifying vegetation clearance issues?
	Should modifications to Appendix B VM QC Check Instructions be made?
VM Quarterly Reports	Are the VM Quarterly Reports being conducted per Section 4.1.24?
	Are the VM Quarterly Reports useful in providing management an assessment of the VM program?
	Should changes be made to the content and/or periodicity of the VM Quarterly Reports?
VM Program	Overall, were the Company's VM Program objectives achieved?
	Are changes recommended to the VM Program Policy and Procedures?
	Are changes in the Company's execution of its VM Program warranted?

Appendix C
Vegetation Management Quality Control Form

The VM QC Evaluator shall print the QC map and indicate the location of each discrepancy noted by indicating the discrepancy “type” and an arrow showing the approximate location on the map.

Note: Discrepancies of a significant safety nature that would be classified as Level 1 per GO-95 Rule 18 should be resolved immediately by notifying the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue.

Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

The QC Evaluator shall indicate the total number of discrepancies for each type on this form. Upon completion of the QC, the QC Evaluator shall update the online QC form, sign and date the map, and return the map to Wildfire Mitigation & Reliability Engineer.

Discrepancy Types:

Type 1: Any vegetation that is within 72” from primary conductors. **Total #:** _______

Type 2: Trimmed vegetation that is not trimmed to a minimum of 12’ from primary conductors. **Total #:** _____

Type 3: Any instances of fast growing trees (poplar, aspen, cottonwood) that were not trimmed out to 12' regardless of proximity to line. **Total #:** ______

Type 4: Any instances of vertical coverage above BVES sub-transmission lines (34.5 kV). **Total #:** ______

Type 5: Tree and Major Limb infractions: See Trees and Major Limbs in Close Proximity to Bare Conductors flowchart. **Total #:** ______

Type 6: Any tree that is dead, rotten or diseased, or portions of otherwise healthy trees, which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone. **Total #:** ______

Total # of discrepancies: ______

Comments:

APPENDIX F. BVES ASSET & INSPECTION QUALITY MANAGEMENT PLAN

Bear Valley Electric Service, Inc.
Asset & Inspection Quality Management Plan

December 28, 2021

Paul

Approved by: ______________________________ Digitally signed by Paul Marconi
Date: 2021.12.28 15:34:27 -08'00'

Paul Marconi, President, Treasurer, & Secretary

Purpose: To provide policies and procedures to establish an audit process to manage and confirm work completed by employees or subcontractors complies with applicable technical specifications, standards, and codes and meet wildfire mitigation, safety, and reliability objectives.

Scope: The Quality Management Plan is applicable to all transmission and distribution (T&D) and power generation work with the exception of vegetation management work. A separate document, BVES INC Vegetation Management and Vegetation Management QC Programs Policy and Procedures, outlines the Quality Management Plan for vegetation management work.

Definitions:

Quality Assurance (QA) is the part of quality management focused on providing confidence that quality requirements will be fulfilled. The confidence provided by quality assurance is twofold —internally to management and externally to customers, government agencies, regulators, certifiers, and other stakeholders.

Quality Control (QC) is the part of quality management focused on fulfilling quality requirements. While quality assurance relates to how a process is performed or how a product is made, quality control is more the inspection aspect of quality management.

Quality Improvement is a set of activities that organizations carry out in order to enhance performance (get better results). Improvement can be achieved by means of a single activity or by means of a recurring set of activities.

Quality Management (QM) is the coordinated activities to direct and control and the organization with regard to quality.

Inspection is the process of measuring, examining, and testing to gauge one or more characteristics of a product or service and the comparison of these with specified requirements to determine conformity. Products, processes, and various other results can be inspected to make sure that the object coming off a production line, or the service being provided, is correct and meets specifications.

External (Contracted) T&D Work is defined as when scope of work where the majority and/or critical tasks are performed by a contractor.

Internal T&D Work is defined as when scope of work where the majority and/or critical tasks are performed by BVES employees.

Power Plant Work is defined as when the scope of work is on the Power Plant engines and/or supporting systems.

Substation Work is defined as when the scope of work is within the boundaries of a substation.

Overview: The primary goal of a Quality Management Plan is to ensure that the deliverables from work are of adequate quality and fit-for-purpose. Quality Assurance, Quality Control, and Quality Improvement are integral components of the Quality Management Plan. T&D and power generation work have a direct impact on wildfire mitigations, public and worker safety, and grid resiliency and reliability; therefore, it is essential that work is completed in a manner that is compliant with all applicable technical specifications, standards, and codes.

QA involves thinking about what is required to ensure quality will be achieved, and to set out processes, standards, procedures and/or policies to do that. Typical results of QA are quality plans, inspection and test plans (ITPs), documentation and training. It moves a step up from finding the failures to aiming to prevent or eliminate them. The focus of QA is to provide confidence that requirements and standards are met, and that processes and system have been followed. Some examples of QA:

A checklist for assembly of product (the procedure/process as a series of steps that must be done).

A written procedure.

A set of processes for construction that cover the whole 'life cycle' from getting system requirements, through designing the system, procuring the materials or parts, constructing to applicable standards, testing, and placing in operation.

A set of processes for a service that cover the whole 'life cycle' from establishing what the system requires, through designing the service, developing and delivering it.

QC is a procedure or set of procedures intended to ensure that a performed service adheres to a defined set of quality criteria or meets the applicable requirements and technical specifications. While QA refers to the confirmation that specified requirements have been met by a product or service, QC refers to the actual inspection of these elements. In order to implement an effective QC program, the organization must decide which specific standards and technical specifications must be met. Then the extent of QC actions must be determined -- for example, the percentage of structures to be inspected for each job and/or the level of detail for each inspection. Next, the results of the QC actions are analyzed to:

Determine if quality requirements are being fulfilled,

Expose areas where quality requirements are not being met,

Identify areas for process improvement even if quality requirements are being fulfilled, and

Evaluate if QC inspections are sufficient to determine if quality requirements are being fulfilled.

After this, corrective action and/or process improvements must be decided upon and taken, if warranted. Finally, the QC process must be ongoing to ensure that remedial efforts, if required, have produced satisfactory results and to immediately detect recurrences or new instances of trouble.

Roles and Responsibilities:

Utility Manager. Overall responsible for oversight of the quality management program. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

Utility Engineer and Wildfire Mitigation Supervisor. Overall responsible for determining work scope, technical specifications, QA/QC requirements, evaluating QC results, and implementing QC requirements. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

Field Operations Supervisor. Overall responsible for fieldwork and supporting the Utility Manager and Utility Engineer and Wildfire Mitigation Supervisor in their responsibilities. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

Accounting Supervisor. Overall responsible for providing oversight of the procurement of equipment and material and the contracting of labor and services. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

Regulatory Compliance Project Engineer. Responsible for supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Project Coordinator. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

GIS Specialist. Responsible for updating the GIS to document work completed and for supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Field Inspector. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Substation Technician. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Senior Power Plant Operator**.** Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Line Crew Foreman. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

Contracts Administrator. Responsible for ensuring qualified contractors are utilized for contracted work and that the contracting is in accordance with the Company's procurement policies as detailed in Table 6-1, BVES QA Process, in Section 6.

Buyer. Responsible for ensuring qualified vendors are utilized for procurement of equipment and materials, and that the purchasing is in accordance with the Company's procurement policies as detailed in Table 6-1, BVES QA Process, in Section 6.

Storekeeper. Responsible for receipt inspecting material and equipment to ensure it meets the specifications and quality requirements as required by the Purchase Order. Responsible for ensuring material and equipment is properly stored after receipt in accordance with manufacturer directions. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

Quality Management: Table 6-1, BVES QA Process, outlines the standard QA process that BVES follows to achieve the desired quality outcome for T&D and power generation work. Appendix A provides a flowchart of the QA process indicating steps that may be performed in parallel and process improvement loops. Depending on the complexity of the work, the Utility Engineer & Wildfire Mitigation Supervisor may require additional quality steps or may omit quality steps from the QA process as applicable to the specific work scope. Section 7 provides additional guidance on how the QA process is to be implemented.

Quality Step	Activity Description	Staff Involved
1	Determine scope of work (construction, repairs, inspections, etc.).	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Regulatory Compliance Project Engineer.
2	Establish applicable work technical specifications, instructions, standards, and material and equipment requirements (Work Order)	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Regulatory Compliance Project Engineer, Utility Planner, Engineering Technician, & Buyer.
3	Determine qualifications required of personnel performing the scope of work.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
4	Determine level of in process QC and work closeout and acceptance QC necessary to ensure quality requirements are satisfied.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.
5	Select staff to conduct applicable QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.
6	Select qualified contractors (Request for Proposal) and/or staff to conduct the scope of work.	**Responsibility:** Utility Manager **Support:** Utility Engineer & Wildfire Mitigation Supervisor, Field Operations Supervisor, Regulatory Compliance Project Engineer, Accounting Supervisor, & Contracts Administrator.
7	Implement directed in process QC and work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Regulatory Compliance Project Engineer, Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
8	Procure material and equipment (Purchase Order).	**Responsibility:** Buyer **Support (as applicable):** Accounting Supervisor
9	Receipt inspect material and equipment and properly store it.	**Responsibility:** Storekeeper **Support (as applicable):** Buyer, Accounting Supervisor
10	Commence work per scope of work.	**Responsibility:** Field Operations Supervisor **Support (as applicable):** Utility Manager, Utility Engineer & Wildfire Mitigation Supervisor, & Project Coordinator
11	Conduct directed in process QC at appropriate process control points.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
12	Evaluate results of in process QC.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
13	Determine if corrective action and/or process improvements warranted based on in process QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Utility Manager, Field Operations Supervisor, & Project Coordinator.
14	Take corrective action if warranted based on in process QC.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.

15	Implement process improvements if warranted based on in process QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
16	Determine if in process QC is appropriate. If not, implement additional or reduced in process QC as warranted.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.
17	At work reported complete, document work performed (GIS update, work order closing, drawing update, inspection report, etc.).	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Project Coordinator, GIS Specialist, Field Inspector, Substation Technician, Senior Power Plant Operator & Line Crew Foreman.
18	Conduct directed work closeout QC when work is completed.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.
19	Evaluate results of work closeout QC.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
20	Determine if corrective action and/or process improvements warranted based on work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Utility Manager, Field Operations Supervisor, & Project Coordinator.
21	Take corrective action if warranted based on work closeout QC.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.
22	If rework is necessary, ensure applicable in process QC and work close QC are conducted as appropriate.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
23	Implement process improvements if warranted based on work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.

24	Determine if work closeout QC is appropriate. If not, implement additional or reduced work closeout QC as warranted.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
25	Closeout Work Order.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Field Operations Supervisor, Accounting Supervisor, Project Coordinator, GIS Specialist, Field Inspector, Substation Technician, Senior Power Plant Operator & Line Crew Foreman.

Additional QM Guidance. As discussed in Section 6, depending on the complexity of the work, the Utility Engineer & Wildfire Mitigation Supervisor (for T&D work) and Field Operations Supervisor (for Power Plant work) may require additional quality steps or may omit quality steps from the QA process as applicable to the specific work scope. This section provides guidance to be applied when making the determination for what QA will be applied to specific work and activities.

Equipment and Material.

Standard Stock Equipment and Material: The Utility Engineer & Wildfire Mitigation Supervisor shall approve the technical specifications of equipment and material to be maintained in standard inventory stock. Utility Engineer & Wildfire Mitigation Supervisor shall coordinate with the Field Operations Supervisor to determine standard stock minimum and maximum value amounts. Additionally, the Utility Engineer & Wildfire Mitigation Supervisor shall work with the Field Operations Supervisor when determining the specific technical specifications of material to be maintained in stock. The Buyer will place purchase orders for equipment and material to qualified vendors to replenish stock to avoid going below the minimum inventory amounts. The Storekeeper will receipt inspect all standard stock items and report discrepancies to the Buyer and Utility Engineer & Wildfire Mitigation Supervisor. For discrepancies affecting the technical specifications or performance of materials, the Utility Engineer & Wildfire Mitigation Supervisor will direct what corrective action(s) should be taken. For non-technical discrepancies (i.e., wrong amount of material received), the Buyer will direct what corrective action(s) should be taken.

Non-Standard Stock Equipment and Material: The Utility Engineer & Wildfire Mitigation Supervisor shall approve the technical specifications of non-standard stock equipment and material prior to purchasing. The Buyer will place purchase orders for the non-standard equipment and material as listed on the approved requisition to qualified vendors. When the equipment and material is received, the Storekeeper will receipt inspect it and will inform the Utility Engineer & Wildfire Mitigation Supervisor. The Utility Engineer & Wildfire Mitigation

Supervisor will determine if an additional receipt inspection is necessary by a Subject Mater Expert. The following additional receipt inspections will be required by the Utility Engineer & Wildfire Mitigation Supervisor at a minimum:

Substation equipment, capacitor banks, electronic fuse trip savers, and field switches will be receipt inspected by the Substation Technician.
Distribution overhead and pad mounted transformers will be receipt inspected by a Journeyman Lineman or the Substation Technician.
IT and communications equipment and material will be inspected by IT staff.
Weather stations and other digital equipment and sensors will be receipt inspected by IT staff, Substation Technician and/or other SME staff as designated by the Utility Engineer & Wildfire Mitigation Supervisor.
Meters and meter related equipment and material shall be receipt inspected by the Meter Testman.
Power Plant equipment and material will be receipt inspected by the Power Plant Senior Operator.

Discrepancies noted in the receipt inspections shall be reported to the Buyer and Utility Engineer & Wildfire Mitigation Supervisor. For discrepancies affecting the technical specifications or performance of materials, the Utility Engineer & Wildfire Mitigation Supervisor will direct what corrective action(s) should be taken. For non-technical discrepancies (i.e., wrong amount of material received), the Buyer will direct what corrective action(s) should be taken.

Equipment and Material Ordered for Specific Projects: The Utility Engineer & Wildfire Mitigation Supervisor will direct if any additional SME receipt inspection(s) are necessary in addition to the Storekeeper's receipt inspection for equipment and material ordered to support a specific project. For example, if the equipment and material is the same equipment and material maintained in stock, the Storekeeper's receipt inspection would normally be sufficient. The Utility Engineer & Wildfire Mitigation Supervisor should use the guidance in Section 7.1.2 to determine if additional receipt inspections are necessary.

Contracted Services. The Utility Manager shall be responsible for contracting for work from qualified contractors by following the Company's procurement policy. In coordination with the Utility Engineer & Wildfire Mitigation Supervisor, Field Operations Supervisor, Accounting Supervisor, and Contracts Administrator, the Utility Manager shall develop the contracted scope of work and issue a Request for Proposal to qualified contractors. The Utility Manager shall follow the Company's procurement policy in selecting the best value bid from qualified contractors and awarding the contract.

External (Contracted) T&D Work. In coordination with the Field Operations Supervisor, the Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in-process and closeout

QC checks for external T&D work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.

The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.

Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.

The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Field Inspector or a BVES Journeyman Lineman Foreman.

Staff that will be involved in the QC checks shall review the Work Order.

Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.

In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to installing a ground rod the BVES inspector must be on site), and/or a combination the later methods.

Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.

When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.

Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator shall also perform a validation of billing units, and ensures the Field Inspector's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of in process and closeout QC checks and the completed Work Order package and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

Internal T&D Work. In coordination with the Field Operations Supervisor, the Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in process and closeout QC checks internal T&D work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.

Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.

The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by a BVES Journeyman Lineman Foreman.

Staff that will be involved in the QC checks shall review the Work Order.

Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the BVES crew to conduct the work.

In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to installing a ground rod the BVES inspector must be on site), and/or a combination the later methods.

Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.

When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.

Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

The Regulatory Compliance Project Engineer shall perform a work package audit and validate the materials and work performed.

The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of in process and closeout QC checks and the completed Work Order package and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

Substation Work. The Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in process and closeout QC checks for substation work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.

The Utility Engineer & Wildfire Mitigation Supervisor shall approve a specific testing and commissioning program that must be satisfactorily completed prior to accepting major substation work.

The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.

Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.

The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Substation Technician or a BVES Journeyman Lineman Foreman.

Staff that will be involved in the QC checks shall review the Work Order.

Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.

In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to making up switch connections, the BVES inspector must be on site), and/or a combination the later methods.

Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.

When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.

Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.

When conditions are met, the Field Operations Supervisor shall direct performance of

the testing and commissioning program. The testing and commissioning program should generally be conducted by a third party independent of the contractor performing the work and/or the Substation Technician. The Substation Technician shall oversee any third party that performs the testing and commissioning program.
The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of the testing and commissioning program prior to accepting the work as being complete.
Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator also performs a validation of billing units, and ensures the Substation Technician's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

Utility Engineer & Wildfire Mitigation Supervisor shall review the results of closeout QC checks and testing and commissioning program, and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

<u>Power Plant Work</u>. The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall approve specific in process and closeout QC checks for power plant work. The Field Operations Supervisor shall utilize the following guidance:

Prior to authorizing work, the Field Operations Supervisor in coordination with the Senior Power Plant Operator shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order with Engineering and Planning support to direct the specified work.
The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall approve a specific testing and commissioning program that must be satisfactorily completed prior to accepting major power plant work.
The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.
Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.
The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Senior Power Plant Operator or Power Plant Operator.
Staff that will be involved in the QC checks shall review the Work Order.
Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.
In-process QC checks may be designated to be conducted periodically (for example, daily when

work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to reassembly of an engine cylinder, the BVES inspector must be on site), and/or a combination the later methods.
Results of in-process QC checks should be reviewed with the Field Operations Supervisor and the Senior Power Plant Operator and corrective action directed if necessary.
Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.

When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.

Results of closeout QC checks should be reviewed with the Field Operations Supervisor and the Senior Power Plant Operator and corrective action directed if necessary.

When conditions are met, the Field Operations Supervisor shall direct performance of the testing and commissioning program. The testing and commissioning program should generally be conducted by a third party independent of the contractor performing the work and/or the Senior Power Plant Operator. The Senior Power Plant Operator shall oversee any third party that performs the testing and commissioning program.

The Field Operations Supervisor and the Senior Power Plant Operator shall review the results of the testing and commissioning program prior to accepting the work as being complete.

Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator also performs a validation of billing units, and ensures the Senior Power Plant Operator's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

The Field Operations Supervisor and Senior Power Plant Operator shall review the results of closeout QC checks and testing and commissioning program, and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

Appendix A: BVES QA Process Flow Chart