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24-12016

Public Utilities Commission of Nevada
Electronic Filing
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Filed For: NPC SPPC

In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s Caitlin Katzenbach

By electronically filing the document(s),
the filer attests to the authenticity of the electronic signature(s) contained therein.

This filing has been electronically filed and deemed to be signed by an authorized agent or
representative of the signer(s) and
NPC SPPC

March 27, 2025

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Corrected Original Filing - Docket No. 24-12016 – Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their First Amendment to the Joint Natural Disaster Protection Plan.

Dear Ms. Osborne:

On December 17, 2024, Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and with Nevada Power, "NV Energy" or the "Companies") filed for approval of the first amendment to their joint Natural Disaster Protection Plan ("NDPP"). During the course of discovery, the Companies identified confidential operational details related to the Companies' Emergency De-Energization Wildfire Policy ("De-Energization Policy"), which were inadvertently included in Section 2.2.3 to the original 2024-2026 Natural Disaster Protection Plan First Amendment ("First Amendment") and Appendix A thereto. This corrected original filing provides appropriate redactions.

This corrected filing also provides a public and lightly-redacted copy of the Companies' Emergency De-Energization Policy, which was included as Appendix B to the First Amendment document in the Application. In the Companies' initial Application, NV Energy marked the entire Emergency De-Energization Policy as confidential. The version included herein includes limited redactions that protect information that (1) reveals critical infrastructure of facilities used for transmitting electricity[1] or (2) provides records or other information that reveal information about specific emergency response plans and tactical operations.[2]

Finally, this corrected filing also addresses minor corrections to the First Amendment document to insert a table that was inadvertently omitted from the initial filing. Specifically, the First Amendment did not include a table outlining the headcount associated with the proposed new NDPP programs included in the Application (i.e., the Hazard Awareness Desk and Distribution Automation positions). Though not included in the First Amendment document, this table was cross-referenced as "Table 11 in the First Amendment" in Ms. Howard's direct testimony.[3] Ms. Howard's subsequent testimonial cross references to tables in the First Amendment are also misnumbered due to the inadvertent omission of Table 11. The attached corrected filing provides

[1] *See* Nevada Revised Statutes ("NRS") Section 239C.210(2)(b).
[2] *See* NRS Section 239C.210(2)(b).
[3] *See* Ms. Howard's Q&A 29, referencing Table 11 in Exhibit B to the Application.

a revised First Amendment that includes Table 11 and renumbers the remaining tables accordingly to conform with Ms. Howard's direct testimony.

Should you have any questions regarding this filing, please contact me at (775) 834-5793 or michael.knox@nvenergy.com.

Respectfully submitted,

/s/ Michael Knox

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Senior Attorney

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Attorneys for Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy

APPLICATION

Sierra Pacific Power Company
and Nevada Power Company
d/b/a NV Energy

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their First Amendment to the Joint Natural Disaster Protection Plan.	Docket No. 24-12___

JOINT APPLICATION TO APPROVE FIRST AMENDMENT TO THE NATURAL DISASTER PROTECTION PLAN

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") make this Joint Application, pursuant to Nevada Revised Statute ("NRS") § 704.7983 for approval by the Public Utilities Commission of Nevada ("Commission") of the First Amendment ("First Amendment") to the Second Triennial Natural Disaster Protection Plan ("NDPP") for the plan years 2024-2026 ("Plan"). Because this is an amendment to the Companies' 2024-2026 Joint NDPP, NRS § 704.7983 and Section 8(2) of the regulations approved by the Commission on January 30, 2020, in Docket No. 19-06009, LCB File No. R085-19 and subsequently revised the regulations approved filed on November 15, 2024, LCB File No. R181-24, require the Commission issue an order accepting or modifying the First Amendment, or specifying any portions of the Amendment it deems to be inadequate, within 180 days after its filing. The statutory period within which this matter must be resolved therefore runs on Sunday, June 15, 2025.

I.

SUMMARY AND INTRODUCTION

NRS 704.7983 requires the Companies to file an NDPP that contains information, procedures and protocols relating to the efforts of the electric utility to prevent or respond to a fire or other natural disaster. The Companies filed their joint 2024-2026 NDPP on March 1, 2023, in Docket No. 23-03003. The Commission issued its Final Order approving, in relevant part, the 2024-2026 NDPP on August 28, 2023.

The First Amendment requests approval of new labor resources plan to implement the Plan's scope of work, as well as confirmation of the enhanced fire season protocols that the Companies implemented in the 2024 fire season to maintain safe and reliable service. This First Amendment also requests new NDPP programs and technologies that are incremental to the Companies' normal course of business but are necessary to harmonize various manual systems and leverage standard industry technology for wildfire mitigation. Lastly, the Companies present a revised, cost-effective approach for the Mt. Charleston rebuild consisting of a clean energy microgrid to mitigate fire risk and lessen the impacts of Public Safety Outage Management in that area.

Neither the labor resource plan nor the implementation of enhanced fire season protocols require an increase to approved NDPP budgets. However, for the requested funding needed for situational awareness and new programs, Table 1 and Table 2 below show the requested budget increases divided into operations, maintenance, administrative and general ("OMAG") expenses and capital costs. The Companies seek an additional $6,316,529 in OMAG and $1,902,535 in capital funding to meet NDPP objectives as updated by the First Amendment. The requested budget for OMAG is shown in Table 1. The capital budget request is presented in Table 2:

Table 1. NV Energy – OMAG First Amendment Request

NV Energy - OMAG Currently Approved and Proposed First Amendment Programs	2024-2026 Approved Triennial Budget	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - OMAG	33,483,214	31,282,813	(2,200,401)
Nevada Power - Currently Approved	33,483,214	28,721,678	(4,761,536)
Nevada Power - Proposed	0	2,561,135	2,561,135
Sierra Pacific Power - OMAG	168,477,977	176,994,907	8,516,931
Sierra Pacific Power - Currently Approved	168,477,977	168,468,159	(9,817)
Sierra Pacific Power - Proposed	0	8,526,748	8,526,748
Grand Total	**201,961,191**	**208,277,720**	**6,316,529**

Table 2. NV Energy - Capital First Amendment Request

NV Energy - Capital Currently Approved and Proposed First Amendment Programs	2024-2026 Approved Triennial Budget	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power	38,139,323	41,685,453	3,546,129
Nevada Power - Currently Approved	22,233,221	21,756,623	(476,598)
Nevada Power – Mt. Charleston	15,906,102	19,417,220	3,511,118
Nevada Power - Proposed	0	511,609	511,609
Sierra Pacific Power	106,122,293	104,478,699	(1,643,594)
Sierra Pacific Power - Currently Approved	106,122,293	99,109,680	(7,012,613)
Sierra Pacific Power - Proposed	0	5,369,019	5,369,019
Grand Total	**144,261,616**	**146,164,152**	**1,902,535**

II.

THE APPLICANTS

Nevada Power and Sierra are Nevada corporations and wholly-owned subsidiaries of NV Energy, Inc. Nevada Power and Sierra are public utilities as defined in NRS § 704.020, and are subject to the jurisdiction of the Commission. Nevada Power is engaged in providing electric service to the public in portions of Clark and Nye counties, Nevada, pursuant to a certificate of public convenience and necessity issued by this Commission. Sierra provides electric service to the public in portions of fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. Sierra owns and operates a certificated local distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada and Nevada Power's primary business office is located at 6226 West Sahara Avenue in Las Vegas, Nevada. All correspondence related to this Application should be served electronically upon the following address: regulatory@nvenergy.com. Hardcopy documents should be transmitted to NV Energy's counsel as set forth below:

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III.

APPLICATION EXHIBITS

To aid the Commission in considering this First Amendment to its NDPP, NV Energy has included with this Application and incorporated herein by reference the following Application Exhibits:

- **Exhibit A** is a proposed notice of the Application as required by NAC § 703.162.
- **Exhibit B** and appendices are the First Amendment to the Second Triennial Plan for plan years 2024-2026.

IV.

SUPPORTING MATERIAL

All material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the request for affirmative relief is set forth herein. Consistent

Sierra Pacific Power Company
and Nevada Power Company
d/b/a NV Energy

with these directives, this Application includes all such additional material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the requests for affirmative relief set forth herein, and is supported by the following witnesses' prepared direct testimony:

Jesse Murray, Vice President, Electric Delivery and Natural Disaster Protection. Mr. Murray presents an overview of the filing and serves as the Companies' policy witness for the NDPP.

Danyale Howard, Director, Natural Disaster Protection Execution. Ms. Howard provides a detailed review of the Companies' proposed adjustments to its NDPP labor resource plan to improve NDPP implementation. Ms. Howard also includes (1) a general overview of the Companies' proposed changes to the fire season protocols, (2) a request to modify Phase 1 of the previously approved Mount Charleston rebuild, (3) a request to approve certain new NDPP programs and technology to improve distribution automation and hazard awareness, and (4) minor modifications to the Tier 3 fire areas maps.

Alexander Hoon, Principal Meteorologist, Natural Disaster Protection. Mr. Hoon discusses the Companies' efforts to enhance Nevada's resilience to wildfire risks and mitigate wildfire hazards.

Joshua Icenhower, PE, System Protection Engineering Manager. Mr. Icenhower supports the Companies' implementation of Fast Trip Fire Mode system protection protocols to mitigate wildfire risk.

Cary Shelton-Patchell, Regulatory Financial Policy Director. Ms. Shelton-Patchell provides rate calculations and bill impacts for First Amendment requests.

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Sierra Pacific Power Company
and Nevada Power Company
d/b/a NV Energy

V.

CONFIDENTIALITY

Appendix B to the First Amendment (Exhibit B) contains confidential information pursuant to Nevada's Homeland Security Act, codified in NRS §239C.210 and Federal Laws relating to Critical Energy Infrastructure Information and Controlled Unclassified Information. Specifically, Appendix B to the First Amendment is NV Energy's Emergency De-Energization Wildfire Policy. This policy document includes detailed information regarding NV Energy's infrastructure and its operational practices in certain emergency response situations. As a result, NV Energy has designated this information confidential pursuant to NRS § 703.190 and NAC § 703.5274.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website.

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential permanently. Confidential treatment of the above-described information will not impair the ability the Staff or the BCP to fully investigate the Companies' proposals. Pursuant to NAC § 703.527 and § 703.5274, Staff and BCP have already executed a protective agreement for this case and will be immediately provided unredacted copies of the filing.

VI.

REQUESTS FOR RELIEF

NV Energy respectfully requests that, pursuant to the regulations adopted in Docket No. 19-06009, LCB File No. R085-19 and LCB File No. 181-24, the Commission issue an order accepting the First Amendment to the NDPP on or before Friday, June 13, 2025, and containing the following findings:

1. Accept the Amendments to the NDPP Plan as it is set forth in **Exhibit B** and the testimony of Mr. Jesse Murray, Ms. Danyale Howard, Mr. Alex Hoon, and Mr. Joshua Icenhower;
2. Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated and respectfully submitted this 17th day of December, 2024.

NEVADA POWER COMPANY
D/B/A NV ENERGY
SIERRA PACIFIC POWER COMPANY
D/B/A/ NV ENERGY

/s/Michael Knox
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EXHIBIT A
DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA

DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(4) (a)):

> **Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their First Amendment to the Joint Natural Disaster Protection Plan.**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(4) (b)):

> **Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy.**

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(4)(c)):

> **Nevada Power Company and Sierra Pacific Power Company are seeking approval of their first amendment to the joint Natural Disaster Protection Plan (NDPP). The Application requests that the Public Utilities Commission of Nevada approve changes to NDPP for the 2024-2026 period. The amendment requests changes to existing programs and approval for proposed initiatives intended to mitigate natural disaster risks. The application includes adjustments to labor resource plans for NDPP existing programs, implementation of new NDPP programs and technologies for situational awareness and distribution automation, modifications to the Mt. Charleston rebuild plan and minor modifications to fire tier maps. This amendment also seeks confirmation of enhanced fire season protocols protocols for the utilities' electric assets in the event of fire weather conditions or related natural disasters.**

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1)[1]:

No. A consumer session is not required by NRS § 704.069.

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

Not Applicable.

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[1] NRS **704.069 states in pertinent part:**

> 1. The Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110 inclusive, in which:
> (a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and
> (b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.

EXHIBIT B FIRST AMENDMENT

Natural Disaster Protection Plan

2024-2026 Natural Disaster Protection Plan First Amendment

December 13, 2024

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1 INTRODUCTION

Summary

Nevada Power Company ("Nevada Power" or "NPC") and Sierra Pacific Power Company ("Sierra" and, together with Nevada Power, "the Companies" or "NV Energy"), request approval of this First Amendment ("First Amendment") to the Second Triennial Natural Disaster Protection Plan ("NDPP") approved in Docket No. 23-03003 for the plan years 2024-2026 (the "Plan"). The First Amendment requests approval of new labor resources required to implement the Plan's scope of work, as well as confirmation of the enhanced fire season protocols that the Companies implemented in the 2024 fire season to maintain safe and reliable service. This First Amendment also requests new NDPP programs and technologies that are incremental to the Companies' normal course of business but are necessary to harmonize various manual systems and leverage standard industry technology for wildfire mitigation. Lastly, the Companies present a revised, cost-effective approach for the Mt. Charleston rebuild consisting of a clean energy microgrid to mitigate fire risk and lessen the impacts of Public Safety Outage Management ("PSOM") in that area.

This First Amendment request is made pursuant to Nevada Revised Statute ("NRS") 704.7983. The Public Utilities Commission of Nevada ("Commission") finalized relevant regulations on January 30, 2020, in Docket No. 19-06009, which were codified by the Legislative Counsel Bureau ("LCB") in LCB File No. R085-19 ("Regulations") on February 26, 2020.[1] Section 7.1 authorizes amendments to the Plan.

From a high-level perspective, the objectives for this First Amendment are to:

- Add internal labor resources for administration of the Plan

Qualified internal labor resources are required to administer approved programs, support community outreach, focus on achieving scheduled milestones, and coordinate or harmonize potentially competing priorities. Through reorganization of existing employees and the addition of the proposed labor resources, the Companies are creating a more mature organization that includes introducing front line leadership relational to the work performed and a manageable span of control to provide clear expectations regarding priorities and actions, coalescing the organization around a culture of risk reduction. This new organization supports the overarching mission, day-to-day activities, and ongoing training. Leverage technology and analytics

The Companies also have determined a need for additional technology to support enhanced granularity and tracking of NDPP programs. Up to this point, work progress and financial reporting for NDPP has been performed largely using spreadsheets and static models. The Companies would benefit from advanced situational awareness and intelligent integration of data on a real-time and forecast basis. For example, satellite imagery can be used to optimize vegetation management resources and predict growth and maintenance cycles. Data warehousing and advanced analytics provide intelligence, including predictions and trends, and support information sharing across the organization. These all underpin a risk based approach to identify and address the highest priority initiatives.

To meet these objectives, the Companies' request is focused in key areas:

Labor Resource Plan for Approved Programs. The labor resource plan funding request includes Full Time Equivalent ("FTE") labor resources to implement the existing approved NDPP initiatives. Positions

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[1] https://www.leg.state.nv.us/Register/RegsReviewed/$R085-19A.PDF. The Commission also recently adopted as permanent revised regulations to implement NRS 704.7983. Docket No. 19-06009, Order, at 5, ¶ 8 (Oct. 11, 2024) (referencing LCB File No. R181-24).

are critically needed to provide prioritized oversight of administrative and field contract functions, enhanced tracking and integrated reporting as part of NDPP directives, capital project design, system operations, and fire incident response and analytics. As discussed in more detail below, these additional positions are needed to ensure timely implementation of the various capital and OMAG programs approved in the Plan. Additionally, the requested internal resources will aid the Companies in addressing concerns raised in the Commission's recent findings regarding the administration of fire agency vegetation management work in Docket No. 24-03006, as well enhancing the oversight of other NDPP related work performed by other third-party contractors. The Companies are not requesting any additional funding for the labor resource plan. The requested positions will be funded using existing budgets.

Enhanced Fire Season Protocols.[2] These protocol refinements were initially filed in an Informational Update in Docket No. 24-07003. These protocols include expansion of PSOM systemwide, deployment of Fast Trip Fire Mode ("FTFM") on selected circuits during fire season conditions to promote public safety, and adoption of NV Energy's Emergency De-Energization Wildfire Policy ("Policy") when a wildfire gets too close to equipment. This Policy was developed with input from the Expert Working Group ("EWG"). Implementation of the enhanced fire season protocols does not require any NDPP budgetary increases.

Address Situational Awareness Gaps. In Docket No. 23-03004, the Commission approved the adoption of Tier 1 into the NDPP. In this First Amendment, NV Energy requests 50 new weather stations and 53 new fire cameras of varying capabilities for situational awareness in the approved Tier areas and to leverage this data for advanced analytics to support the Companies' risk-based approach.

Resource and Technology Plan – Proposed Programs. The proposed programs include FTE resources dedicated to implementation of new NDPP programs requested to support a hazard awareness desk and distribution automation for improved situational awareness and technology-enabled operating practices.

The Companies request funding for technologies that reflect advancements and innovations that have been successfully deployed for other wildfire prone utilities. Rapid innovation in reducing risk and promoting public safety through technology can connect and harmonize disparate systems and better leverage personnel resources. NV Energy also is requesting pilot or demonstration programs that are complementary to the existing programs. Technologies in this request include:

- A hazard awareness desk to serve as the source for reliable, real-time situational awareness across the range of natural disasters approved in the NDPP. The hazard awareness desk will improve the PSOM program through advanced weather forecasting and automated field devices.
- Palantir Foundry, a Wildfire Data Management Platform for improved data and information management to improve timeliness and efficiency of resource deployment that increases data utilization to leverage fire incident analysis and tracking as well as improved de-energization communication to customers and stakeholders.
- AiDash, an intelligent vegetation management platform. Vegetation management is one of the most important aspects of NV Energy's NDPP. AiDash uses satellite, LiDAR, aerial imagery, and other data sources to inform its advanced analytics to optimize vegetation management scheduling and resource allocation. The Companies are requesting a pilot program of AiDash capabilities in select locations across all wildfire risk Tiers. Lessons learned are expected to inform the frequency and approach to vegetation management for improved effectiveness and efficiencies.

Mt. Charleston Rebuild. A cost-benefit analysis indicates that a microgrid is a preferred solution to support the Mt. Charleston area of Southern Nevada. The Companies have updated the four-phased project plan, where the initial phase of the project proposes a microgrid. A clean energy alternative at Mt. Charleston is presented that includes related construction to reliably interconnect and integrate the microgrid into the local infrastructure. As discussed below, NV Energy anticipates an opportunity for grant funding beginning in 2025 from the Department of Energy ("DOE").

Grant Funding from the Grid Resilience and Innovation Partnership ("GRIP") Program. Recent announcements from the DOE include an invitation for NV Energy to enter into negotiations for grant

[2] Enhanced Fire Season Protocols were presented in July 2024 to the Commission in the Informational Update filed Docket No. 24-07003. The entire Informational Update is attached as Appendix A.

funding under GRIP program Funding Opportunity Announcement ("FOA") 3195-2173 Topic Area 2 to accelerate resilience efforts through match funding from the DOE. The Companies will provide a final approved grant implementation plan when that information is available. Negotiations are anticipated for Q1 2025, with a final schedule and budget that is expected to extend into the next NDPP filing cycle.

Mapping Corrections Related to Wildfire Tiers. The Companies request to resolve two separate geographic information system ("GIS") mapping gaps, one for Mt. Charleston Tier 1 and one for Lake Tahoe Tier 2.

NV Energy First Amendment Request

As noted above, neither the labor resource plan nor the implementation of enhanced fire season protocols require an increase to approved NDPP budgets. However, for the requested funding needed for situational awareness and new programs, Table 1 and Table 2 below show the requested budget increases divided into operations and maintenance ("OMAG") and capital for NV Energy. The Companies seek an additional $6,316,529 in OMAG and $1,902,535 in capital funding to meet NDPP objectives as updated by the First Amendment. The requested budget for OMAG is shown in Table 1. The capital budget request is presented in Table 2.

Table 1. NV Energy – OMAG First Amendment Request

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Grand Total	**144,261,616**	**146,164,152**	**1,902,535**

2 FIRST AMENDMENT REQUESTS

2.1 Labor Resource Plan for Approved Programs

NV Energy is requesting resources to implement approved NDPP programs. When the Companies first embarked on the NDPP, the approach utilized was to rely largely on contracted resources with minimal increases to internal labor. With additional experience, stakeholder feedback, a finalized set of regulations governing the program, and taking into account Commission directives, the Companies believe that the addition of internal labor resources are required to effectively oversee and manage these programs, including the large, contracted workforce. The personnel requested in the labor resource plan also reflect the transition of this work to "normal course of business" because these full-time positions are needed to deliver on the NDPP programs during the current plan period and over the long term.

Table 3 below demonstrates the significant average amount of contract workforce used for the NDPP in 2023 and 2024.

Table 3. 2023 and 2024 Estimated Contract Work Force

2023, 2024 NDPP Contract Workforce	Estimated Contractors
NDPP Core Team (contractor support)	18
Lines Construction	70
Fire Prevention Specialists	5
Environmental Services	10
Vegetation Management*	152
Fire Agency Ground Fuels and Fire Stand-By*	120
Third-Party Ground Fuels, Helicopter and Logging*	65
Weekly Fuel Sampling	5
System Hardening Distribution Design	3
Civil Design	3
Project Management	4
Radio Technician	1
LiDAR	2
Total	458
* Vegetation Management crew sizes vary from 5 to 10 persons depending on work type. This comparison uses a conservative number of crews assigned at an average crew size of 8 persons.	

Contracted resources have steadily increased as the program has been executed; however, internal labor used for oversight of those resources did not increase to the same equivalency. The mismatch in external contracted resources and internal labor necessary to administer these contactors has created issues in implementing approved NDPP programs and managing third-party resources.

The NDPP reorganization proposed in the First Amendment's labor resource plan aims to establish a manageable span of control by adding front-line leadership to oversee the contract and internal workforce, organized by sub-groups based on related functions. The labor resource plan recognizes the critical roles and responsibilities needed to ensure alignment with industry risk mitigation practices as well as completion of currently approved NDPP programs. Moreover, the resource plan was developed considering feedback from the Commission to identify the labor resources needed for more robust oversight of third party contractors performing NDPP related work.

Key areas where additional resources are needed to support the NDPP are:

- Policies, Procedures, and Documentation – A mature organization has a comprehensive and coordinated set of natural disaster mitigation policies and procedures that are expected to continually evolve as technology and industry practices advance. This provides clear expectations regarding priorities and actions, coalescing the organization around a culture of risk reduction. These materials support the overarching mission, day-to-day activities, and a cadence of training to ensure evolving practices are consistently demonstrated by internal employees and in the oversight of any contractor supporting the program. With multiple anticipated grant awards, administration, and oversight of work progress, financial accountability, environmental tracking, and coordination across a variety of agencies and organizations, additional resources are needed to support internal and external requirements and obligations.
- Data-Driven Analysis – Analysts and technical professionals are needed to manage and process information across multiple programs to support optimized NDPP risk reduction. Moving from the siloed, spreadsheet-based approach to a data-driven culture supports the identification and mitigation of potential risk, avoiding maladaptive solutions.
- Design, Administration, and Operations – Uniquely qualified specialists as individual contributors who have oversight of specialty contractor resources are necessary to evaluate the system design more holistically. These resources would work across business units to develop suitable resiliency standards over time. Qualified resources will design NDPP-specific infrastructure, manage programs, support community outreach, focus on achieving cost and schedule milestones, coordinate to harmonize potentially competing priorities, and supplement with specialized NDPP knowledge and skills.

The resources requested in this First Amendment to implement existing programs include a total of 31 positions to close identified resource gaps, as shown in Table 4 below. These NDPP personnel are required to implement the approved scope of work, operate the system reliably and efficiently, properly administer the additional funding from anticipated grants, and continue to reduce risks from natural disasters. The proposed positions will be prioritized for day-to-day NDPP projects and programs, ensuring support is available to meet the milestones and achieve risk reductions of the NDPP. Importantly, the Companies are not requesting additional funding for these positions. The Companies will incorporate the positions into the approved Plan budget.

Table 4. Adjusted Labor Resource Plan for Approved NDPP Programs

Adjusted Labor Resource Plan for Approved NDPP Programs	Count
Compliance Reporting	
Sr. Operations Analyst	1
Distribution Design	
Sr. Utility Design Coordinator - Nevada Power	1
Sr. Utility Design Administrator - Sierra Pacific	3
Sr. Regional Engineer/Standards Engineer	1
General Foreman (GF)	1
Project Management	
Procurement Analyst	1
Electric Lines Inspection	
Troubleshooter	5
Electric Inspector	2
System Operations (aka System Control)	
Distribution Outage Coordinator	1
Distribution Operator	4
Vegetation Management	
Sr. Vegetation Management Administrator (VMA), Aerial, Nevada Power	1
Senior Project Manager	1
Vegetation Management Administrator ("VMA"), Ground Fuels, Sierra Pacific	5
Business Coordinator, Ground Fuels Invoice	1
Fire Mitigation and Emergency Response	
Manager, Fire Mitigation	1
Fire Mitigation Officer ("FMO")	1
Sr. Emergency Manager Administrator	1
Total New Personnel	31

The following information details the role of the new personnel proposed in the amended NDPP labor resource plan:

- **Compliance Reporting**
  - *Senior Operations Analyst* – will coordinate with the compliance manager and contracted content writer(s) to develop standardized reports for the NDPP team, provide internal reporting within NV Energy, and support reporting requirements to the Commission and other regulatory entities.
- **Distribution Design**
  - *Utility Design Administrator ("UDA")/Utility Design Coordinator ("UDC")* – UDAs are specific to Sierra Pacific and perform all capital fire mitigation and grid resilience system design estimation and coordination cradle to grave, while overseeing additional third-party contractors needed to meet an adequate level of design to meet NDPP system hardening milestones. The utility design coordinator is specific to Nevada

Power to perform coordination of design activities but does perform the design function.[3]

- *Senior Regional Engineer/Standards Engineer* – will be responsible for ensuring NDPP project designs adhere to good engineering practices. This engineer will be the subject matter expert for fire mitigation, grid resilience designs, and risk mitigation applications, and this position is expected to work with peer utilities to stay abreast of technology and protocols. The engineer will also be responsible for developing and refining pre-engineered fire mitigation standards for inclusion in a library of the Companies' NDPP-specific design and construction standards.

- *General Foreman* – will provide lines experience within NDPP to improve consistency; providing quality assurance of design constructability and material review, and managing any standard deviations; will be the NDPP subject matter expert and liaison to connect with lines personnel in the general business units; and will develop and enforce inspection criteria that troubleshooters and inspectors use for quality assurance/quality control ("QA/QC") of the third-party contractor work performed in fire Tiers.

- **Project Management**
  - *Procurement Analyst* – will be responsible for contract administration for the large volume of contractor-dependent work. This work will include contract creation and modification, managing requests for proposals ("RFPs"), generating purchase requisitions and purchase orders, and the oversight and monitoring of contract-related ancillary functions to ensure consistency.

- **Electric Lines Inspections**
  - *Troubleshooter and Electric Inspector* – will initiate and prepare detailed system switching orders for NDPP system hardening and vegetation management projects that require planned outages and a qualified person to hold line clearance during the outages. These positions will also oversee NDPP third-party lines construction field work, including system hardening, grid resilience, fuse replacements, and corrections resulting from circuit patrols and detailed inspections. Electric inspectors will also perform underground inspections for excavation and substructure work by third-party civil construction crews.

- **System Operations**
  - *Distribution Outage Coordinator and Distribution Operator* – will research system impacts, identify potential conflicts, and perform a holistic coordination among the Companies' other planned projects. These personnel also will actively work with troubleshooters and inspectors in real-time to de-energize and re-energize facilities for NDPP projects including vegetation management, system hardening, PSOM, and emergency de-energization. These resources also respond to emergency calls, including for downed wires; unplanned outages; fire agency reports of active fires (not related to equipment caused fires); vehicle accidents; and other outage incidents. As unplanned events impact the system in conjunction with planned work on the system, system operators adjust system configurations to the extent they can maintain safe operations.

- **Vegetation Management**

[3] Nevada Power UDC responsibilities are represented by Collective Bargaining Unit ("CBA") job duties. Sierra Pacific UDAs are not represented.

- *Vegetation Management Administrators ("VMA")* – will oversee approximately 15 to 25 third-party contract crews performing hazardous ground fuels removal. In this role, the VMAs replace the activities previously conducted by the Fire Mitigation Specialist and Fire Mitigation Officers. Existing VMAs will continue to coordinate and oversee 19 or more crews for traditional aerial clearance and facilitation of helicopter and logging operations as needed.

- *Senior Project Manager* – will strategically scope and identify job site pre-requisites and coordinate annual schedules for both aerial and hazardous ground fuels removal. This will include multi-agency coordination for helicopter operations and logging and Resilience Corridor obligations. Project managers are responsible for budget forecasts, managing cash flow, and analyzing actual costs versus estimates.

- *Business Coordinato*r – will be the first invoice reviewer for vegetation management activities and will also be tasked with ensuring costs tie to contract terms.

- **Fire Mitigation and Emergency Response Coordination**

  - *Fire Prevention* Manager – is the lead Fire Mitigation Officer role responsible for developing, coordinating and overseeing all fire incident response activities including the new emergency de-energization wildfire policy, liaison for fire investigations, internal and external stakeholder training, incident analysis, reporting and coordination with public safety cooperators.

  - *Fire Mitigation Officer ("FMO")* – will have a more fire specialized role going forward and will be phased out of direct control over vegetation management. FMOs will be responsible key criteria determination for emergency de-energization, root cause incident analysis of fire starts on the system in addition to fire investigations and all associated tracking and reporting; post- and predictive analysis and investigations will continue to be performed throughout the "off peak" fire season; will develop and deliver utility training to the EWG public safety partners as part of the ongoing cooperative exercises; and will develop curriculum and deliver annual wildland training and fire safety and awareness training to more than 30 internal business units, including all field operations groups.

  - Emergency Manager Administrator – will be responsible for developing and facilitating tabletop emergency management exercises and training to ensure the Companies are prepared for emergency response. The manager also will oversee the volunteer Incident Management Team to ensure the Companies' individual business units are prepared for a coordinated response to emergency events.

The positions listed here have been calibrated with leading industry practices from other utilities experiencing significant wildfire risk. These positions will also support the other natural disasters that have been identified for the service territories.

The adjusted budgets for the requested labor resource plan, reconciled with the previously approved budgets, is shown in Tables 5, 6, and 7. Table 5 and Table 6 show that no increase is required for OMAG spending for Nevada Power and Sierra, respectively. Table 7 concerns the capital spending for Sierra, which also shows no increase over proposed budgets. It should be noted that there is no capital table for Nevada Power, as the labor resource plan does not require any additional Nevada Power capital spending.[4]

[4] The capital spending for the Mt. Charleston rebuild is addressed in section 2.5 below.

Table 5. Nevada Power OMAG - Adjusted Labor Resources for Approved NDPP Programs

Nevada Power - OMAG Currently Approved NDPP Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor Resource Plan	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Inspections, Patrols, Corrections	4,789,432	1,345,878	0	1,345,878	(3,443,553)
Public Safety Outage Management	4,092,679	4,092,679	100,642	4,193,321	100,642
Risk Based Approach	3,199,338	4,111,068	1,153,763	5,264,831	2,065,493
Situational Awareness	268,667	330,090	0	330,090	61,423
System Hardening	2,017,521	1,543,645	0	1,543,645	(473,876)
Vegetation Management	19,115,577	15,314,351	729,561	16,043,912	(3,071,665)
Grand Total	**33,483,214**	**26,737,712**	**1,983,966**	**28,721,678**	**(4,761,536)**

Table 6. Sierra OMAG - Adjusted Labor Resources for Approved NDPP Programs

Sierra Pacific Power - OMAG Currently Approved NDPP Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor Resource Plan	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Inspections, Patrols, Corrections	26,096,169	15,490,304	72,500	15,562,804	(10,533,365)
Public Safety Outage Management	3,690,036	3,690,036	150,963	3,840,999	150,963
Risk Based Approach	10,433,599	9,772,342	3,265,256	13,037,598	2,603,999
Situational Awareness	1,520,819	1,523,052	0	1,523,052	2,233
System Hardening	10,270,009	9,704,476	72,500	9,776,976	(493,033)
Vegetation Management	116,467,345	120,268,571	4,458,160	124,726,731	8,259,386
Grand Total	**168,477,977**	**160,448,781**	**8,019,379**	**168,468,159**	**(9,817)**

Table 7. Sierra Capital - Adjusted Labor Resources for Approved NDPP Programs

Sierra Pacific Power - Capital Currently Approved NDPP Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor Resource Plan	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Risk Based Approach	10,323	10,908	0	10,908	585
Situational Awareness	1,450,918	1,350,918	0	1,350,918	(100,000)
System Hardening	104,661,052	93,354,964	4,392,890	97,747,854	(6,913,198)
Grand Total	**106,122,293**	**94,716,790**	**4,392,890**	**99,109,680**	**(7,012,613)**

The Companies will carefully integrate the new positions requested in this labor resource plan in managed phases that coincide with continued implementation of seasonal NDPP deliverables. The first phase will focus on front-line leadership, vegetation management oversight, and system hardening design functions. In the first phase, the Companies will onboard new NDPP leadership to develop and refine baseline procedures. The NDPP leadership will prepare for onboarding new employees and additional contractors to continue NDPP execution in coordination with seasonal timelines. Distribution design functions for system hardening, including the engineer and electric lines general foreman, are needed to stage materials and contractors and complete system hardening projects planned for 2025 and beyond. In addition to design support, the engineer and general foreman will develop outage coordination plans for the construction season.

Adding VMAs during the first phase will facilitate prerequisite work, such as permitting and crew coordination. It will also allow FMOs to transition from vegetation management to fire prevention and emergency response duties for the 2025 fire season.

In the second phase, the Companies will onboard system operations personnel needed to review and approve switching orders and execute switching procedures for the system hardening project line up. New lines troubleshooters and inspectors will oversee third-party contract crews deployed among the different regions of Northern Nevada during future construction seasons. Lastly, the adjusted incremental resource plan accommodates the anticipated need for 6-8 interns or contract resources needed to supplement meteorology, GIS and foresters to create prescribed fuels mitigation plans as needed. Two contract business coordinators will be on-boarded temporarily to help stabilize the invoice process. The Companies anticipate business coordinator contractors will not be needed once efficiencies are realized for invoice review.

Overall, the Companies expect implementation of the labor resource plan will take at least 18 months and final acclimation for these groups will take 24 months. During 2026 the team will develop the third triennial plan and at that time, also assess fluency to determine which NDPP functions may acclimate more fully to general business units.

2.2 Enhanced Fire Season Protocols

Enhanced fire season protocols represent operational measures that can be deployed in the short term in conjunction with the implementation of longer-term solutions such as vegetation management and hardening and ruggedization. As the effects of climate change result in weather events of increasing intensity, these protocols leverage operational practices to reduce risk and promote public safety.

In July 2024 in Docket No. 24-07003, the Companies filed an Informational Update outlining their enhanced fire season protocols. The Companies implemented these protocols for the 2024 fire season based on 2024 forecasted heightened fire risk, which subsequently materialized. In this First Amendment, the Companies are requesting confirmation that the enhanced fire season protocols are included in the NDPP, but the Companies are not requesting any increased costs associated with these protocols.[5]

Adopting enhanced fire season protocols as a risk reduction measure does not change the Companies' NDPP risk based approach, schedule, or justification for any other program. More specifically, the Companies are not using de-energization protocols in lieu of other risk mitigation programs or practices.

The Companies' enhanced fire season protocols:

- Implement PSOM systemwide for both the transmission and distribution systems;

- Implement FTFM for Tiers 3, 2, and 1E; and

[5] To the extent needed, the Companies may request recovery associated with implementation of the enhanced fire season protocols in a GRC.

- Implement the Companies' Emergency De-Energization Wildfire Policy systemwide. This Policy has been attached confidentially as Appendix B to this First Amendment.

2.2.1 Extend PSOM Systemwide

One of the operational practices discussed in Docket No. 24-07003 includes extending PSOM systemwide. Tier 1E protocols are proposed as the standard to apply across both Companies' service territories. This provides an equivalent measure of protection for all customers regardless of geographical location and lowers the likelihood that the inherent imprecision of forecasts could compromise public safety. Historical weather data indicates PSOM events outside of Tiers 3, 2, and 1E would be infrequent and unlikely. However, as the effects of climate change result in increasingly intense and frequent weather events, the Companies will continue to monitor and model the trends related to natural disasters. Future filings will timely indicate any findings that result from this proposed change and future plans will incorporate climate insights and related weather impacts to the service territory.

2.2.2 Fast Trip Fire Mode

FTFM is used to rapidly and automatically de-energize power lines in response to abnormal electrical activity, such as faults caused by high winds or damaged infrastructure. The FTFM settings are the most sensitive and are only used during extreme fire weather conditions as a protective measure in advance of PSOM.[6] The Companies activated FTFM as a protective measure during the 2024 fire season.

Under FTFM, protective relays interrupt the flow of power in one-tenth of a second to limit potential sparking produced by a fault. FTFM offers near-instantaneous protection beyond the no-reclose protocols during fire season that may have a time delay for sequenced operation. This rapid response is critical in high or very high fire danger conditions, providing an additional layer of protection between enhanced seasonal fire mode protocols[7] where an arcing condition could last a few seconds and PSOM proactive de-energization. FTFM is implemented as an automated protection scheme and reduces the potential of equipment caused ignition. As a common industry practice, FTFM lowers risk as a practical alternative to PSOM, which is only used when the risk of leaving the grid energized outweighs the risk of de-energizing. FTFM also brings NV Energy into alignment with the practices of other utilities that use FTFM in addition to PSOM. Pacific Gas & Electric ("PG&E") found that its equivalent FTFM program has resulted in a 68 percent reduction in reportable ignitions.[8] Under FTFM, the system will be visually observed in Tier 3 before reclosing and visually observed as needed in the remaining Tiers.

NV Energy uses the U.S. Forest Service ("USFS") Severe Fire Danger Index ("SFDI")[9] to inform FTFM implementation. The USFS's SFDI defines different levels of fire danger, including Low Fire Danger, Moderate Danger, High Fire Danger, Very High Fire Danger, and Extreme (Severe) Fire Danger. The Companies will activate switches on the system to transition the system between Fire Season No-Reclose Mode and FTFM based on the daily and forecasted SFDI. NV Energy's meteorology team

[6] NV Energy will implement FTFM in Tier 3 areas when the United States Forest Service Severe Fire Danger Index indicates High Fire Danger and above and in Tier 2 and Tier 1E areas at Very High Fire Danger and above.

[7] Seasonal Fire Mode disables reclosing of circuits during fire season. This mode may also be referred to as Fire Season No-Reclose Mode.

[8] https://www.pge.com/content/dam/pge/docs/outages-and-safety/safety/epss-fact-sheet.pdf

[9] The SFDI is an early-warning system that could anticipate the conditions that promote large, high intensity fires to provide advanced notice to fire-prone communities and preventing wildland firefighter entrapments and fatalities. Severe Fire Danger Index: A Forecastable Metric to Inform Firefighter and Community Wildfire Risk Management by W. Matt Jolly, et al. Missoula Fire Sciences Laboratory, Rocky Mountain Research Station, USDA Forest Service, *Fire* 2019, *2*(3), 47; https://doi.org/10.3390/fire2030047.

monitors these conditions and notifies system control, lines departments, and substation leadership of impending conditions.

NV Energy's phased approach to system protection settings will generally occur as follows:

1. In late spring or early summer, NV Energy will set to Fire Season No-Reclose Mode when conditions reach Moderate Fire Danger as defined by the USFS. This corresponds to when vegetation dryness has reached a point where a fire ignition may occur, but fire spread is not expected to be a major threat.

2. NV Energy will selectively implement FTFM settings as fire danger increases through the summer, vegetation dryness becomes critical, and fire spread becomes a greater concern. NV Energy will implement FTFM in Tier 3 areas when the USFS SFDI indicates High Fire Danger and Tier 2 and Tier 1E areas at Very High Fire Danger. FTFM was enabled in Tier 3 on July 6, 2024.

The July 3, 2024, NDPP Progress Report, included as Appendix A, provides additional implementation details.

North:[10] Equipment to enable FTFM capability was installed in the North during 2023 for Tier 3. In 2024, the Companies expect to complete 75 percent of the equipment modifications for Tiers 2 and 1E, anticipating 100 percent completion in 2026 due to long lead time for acquiring the necessary equipment. NV Energy will continue to install the approved TripSavers under NDPP in the North. Where the Companies are accelerating beyond the approved Plan for additional equipment, charges will be recovered through the general rate case ("GRC").

There are no separate operating costs for activating FTFM, although FTFM can result in unplanned outages that are no different from other system protection programs.

The FTFM activities required to effectuate FTFM in Tiers 3, 2 and 1E associated with the First Amendment request are shown in Table 8. The proposed cost recovery for these activities is also shown in Table 8.

Table 8. GRC and NDPP Allocations for FTFM

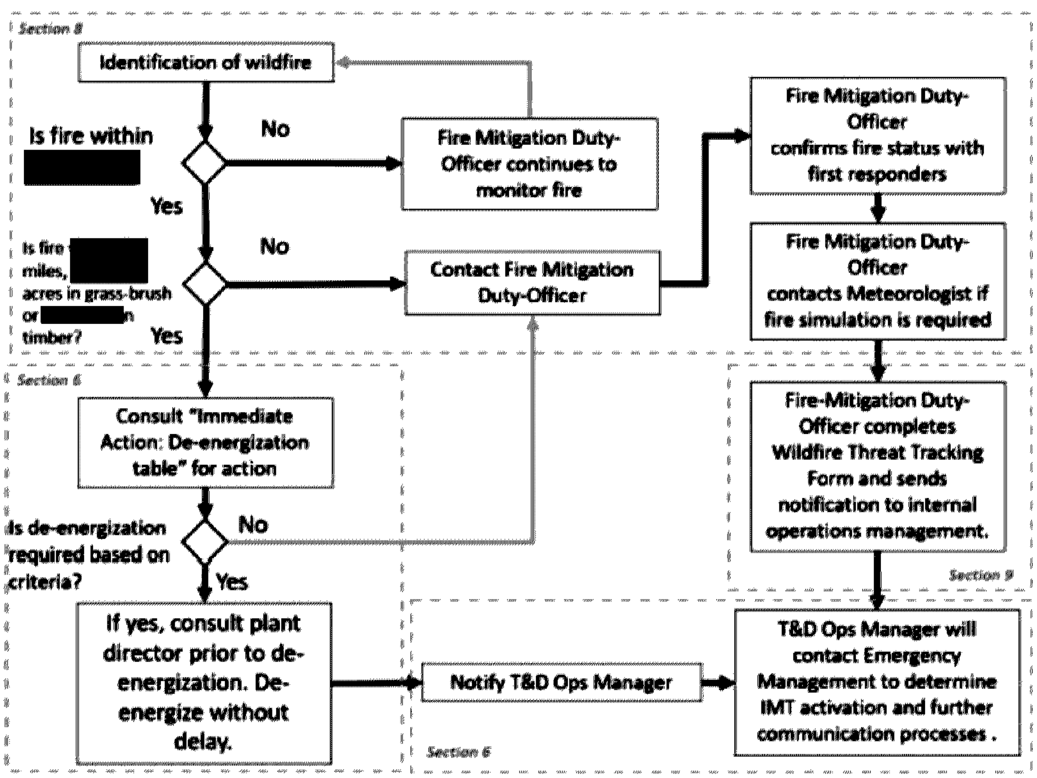
Activity	GRC	NDPP
Extensive reprogramming of exiting recloser setting	Engineering and field labor	N/A
Replace existing field devices with FTFM-capable equipment	Equipment and labor	N/A
Replace incompatible substation equipment	North: equipment and labor	N/A
Install TripSavers North	TripSavers accelerated beyond the approved NDPP 2024 budget amount	TripSavers designated for 2024 installation under the approved NDPP capital budget

[10] The South's implementation of FTFM will be addressed in the Mt. Charleston rebuild.

2.2.3 Emergency De-Energization

The Emergency De-Energization Policy is designed to protect vulnerable infrastructure when a fire approaches. NV Energy has formalized protocols to ensure employees have a clear understanding of actions to be taken during emergencies that apply to the distribution and transmission system. This supports decision making from the front lines to executive leadership, eliminating potential delays that could have devastating consequences. Implementing the Policy systemwide supports equivalent risk reduction for all communities and customers. Emergency De-Energization includes transmission, distribution, and generation that resides within the predefined criteria radius.[11] Historically, fire agencies typically request de-energization due to fire activity so the use of de-energization as a safety practice is not new. The Emergency De-Energization Policy formalizes the practice so it can be both utility and fire agency driven. With rigid implementation criteria, this safety measure is transparent and avoids second-guessing during critical time windows. A summary of the Policy is shown in Figure 1.

Figure 1. Summary of Emergency De-Energization Policy



The Companies ran interactive feedback sessions with the EWG and received feedback that they are in general agreement with the concept. EWG recommendations incorporated into the Policy include:

- Changing the activation timeframe to [redacted] from [redacted];
- Clarifying language and definitions that avoid confusion with fire industry terms; and
- Providing more discretion to determine whether a fire meets the definition of uncontrolled and unpredictable, to avoid activating the Policy for all fires.

[11] The predefined criteria radius is addressed in the Policy included confidentially in Appendix B to this First Amendment.

Future considerations requested by the EWG include:

- Predictive polygons to identify outage areas on a forward-looking basis to determine direction and speed of fire spread according to wind and fuel paths;
- Discussion and refinement of the appropriate radius as more experience is gained; and
- Development of exclusion zones for critical facilities such as water supply and air tanker bases used for fire suppression.

The Emergency De-Energization Policy was activated six times in the 2024 fire season. No incremental costs were incurred to implement the Policy as no new equipment was required.

The Companies are not requesting any funding at this time for de-energizations events.

2.3 Situational Awareness Improvements

This First Amendment includes a funding request to deploy weather stations and wildfire cameras in Tier 1, as well as to fill in any necessary gaps that have been identified in Tiers 3, 2, and 1E. The expanded capabilities from additional weather stations and wildfire cameras will support the ability to lower risks of natural disasters. The information will also be incorporated into the Companies' analytics platforms.

2.3.1.1.1 Weather Stations

The Companies are requesting funding for an additional 50 weather stations. Weather is a key driver of operational mitigation efforts such as FTFM or PSOM. As knowledge is gained about weather patterns in the wildfire Tiers, it can inform other NDPP programs such as hardening initiatives, emergency response, and communications. This request anticipates 45 weather stations in the North and five in the South. These weather stations will improve situational awareness to remote and disadvantaged communities in Nevada.

2.3.1.2 Fire Cameras

The Companies are requesting funding for an additional 53 cameras. Wildfire cameras provide continuous monitoring of wildfires and more recently NV Energy has integrated its camera network with AlertWest for broader situational awareness across neighboring states in the West. Early detection is of critical importance to the Companies and their EWG partners. A combination of complementary camera technologies includes long-range and short-range wildfire cameras. The long-range cameras are typically placed on mountain tops or areas with very large viewsheds to detect wildfires approximately 10 miles away. The short-range cameras are placed on distribution or transmission poles for views of smaller areas with more detail for potential ignitions. Short-range cameras in Tier 3 include the FireBIRD cameras deployed in the Mt. Charleston area in 2024.

The suggested fire camera placement for this request includes:

- 30 long-range wildfire cameras, with 25 placed in the North and five in the South
- Three long-range mobile cameras, with two placed in the North and one placed in the South
- 20 short-range cameras, with 10 placed in the North and 10 placed in the South

Table 9 and Table 10 show the Companies' funding request associated with improved situational awareness by adding wildfire cameras and weather stations. Table 9 shows the OMAG budget requests for Nevada Power and Sierra. Table 10 shows the capital budget request for Nevada Power and Sierra.

Table 9. Situational Awareness - OMAG

NV Energy - OMAG Enhanced Fire Season Protocols	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - OMAG	**268,667**	**488,034**	**219,367**
Situational Awareness - Wildfire Cameras	**199,163**	**300,672**	**101,509**
Wildfire Cameras - Currently Approved	199,163	174,608	(24,555)
Wildfire Cameras - Additional	0	126,064	126,064
Situational Awareness - Weather Stations	**69,504**	**187,362**	**117,858**
Weather Stations - Currently Approved	69,504	155,482	85,978
Weather Stations - Additional	0	31,880	31,880
Sierra Pacific Power - OMAG	**1,520,819**	**2,260,836**	**740,017**
Situational Awareness - Wildfire Cameras	**1,163,394**	**1,427,322**	**263,928**
Wildfire Cameras - Currently Approved	1,163,394	960,518	(202,876)
Wildfire Cameras - Additional	0	466,804	466,804
Situational Awareness - Weather Stations	**357,425**	**833,514**	**476,089**
Weather Stations - Currently Approved	357,425	562,534	205,109
Weather Stations - Additional	0	270,980	270,980
Grand Total	**1,789,486**	**2,748,870**	**959,384**

Table 10. Situational Awareness - Capital

NV Energy - Capital Enhanced Fire Season Protocols	2024-2026 Approved Triennial Budget	2024-2026 Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - Capital	**389,211**	**865,166**	**475,955**
Situational Awareness - Wildfire Cameras	**389,211**	**755,411**	**366,200**
Wildfire Cameras - Currently Approved	389,211	389,211	0
Wildfire Cameras - Additional	0	366,200	366,200
Situational Awareness - Weather Stations	**0**	**109,755**	**109,755**
Weather Stations - Currently Approved	0	0	0
Weather Stations - Additional	0	109,755	109,755
Sierra Pacific Power - Capital	**1,450,918**	**2,969,713**	**1,518,795**
Situational Awareness - Wild Fire Cameras	**1,450,918**	**1,981,918**	**531,000**
Wildfire Cameras - Currently Approved	1,450,918	1,350,918	(100,000)
Wildfire Cameras - Additional	0	631,000	631,000
Situational Awareness - Weather Stations	**0**	**987,795**	**987,795**
Weather Stations - Currently Approved	0	0	0
Weather Stations - Additional	0	987,795	987,795
Grand Total	**1,840,129**	**3,834,879**	**1,994,750**

2.4 Resource and Technology Plan to Implement New Programs

Separately, the Companies are requesting resources to implement new proposed programs and enabling technologies to best leverage NDPP resources. The Resource and Technology Plan – New Programs is based on analyses that indicate that NV Energy would benefit from specialized resources to evaluate the system holistically and to work across business units, supplementing existing resources.

NV Energy is requesting resources to implement new programs for both personnel and technology as follows:

Table 11: Proposed Resource and Technology Headcount and Programs

Labor Resources for Proposed First Amendment Programs	**Count**
Hazard Awareness Desk	
Hazard Awareness Analyst	5
Distribution Automation	
Manager, Distribution Automation	1

Electrical Engineer II	1
Journeyman Lineman	4
Distribution SCADA, Relay Technician	2
Construction Administrator Coordinator	1
Telecommunications Technician	1
Total New Personnel	15
Technology Resources for Proposed First Amendment Programs	
Palantir Foundry, Fire Incident Analysis	
AiDash Vegetation Management Pilot Program	

2.4.1 Personnel to Implement New Initiatives

Hazard Awareness Desk: Many utilities in wildfire prone areas have implemented a hazard awareness desk to expedite response to identified risk across entire service territories. Hazard awareness centers pool multiple sources of intelligence and communication into a single hub manned by personnel with expertise in weather behavior and fire response operations and other emergency actions. NV Energy is requesting a hazard awareness desk based on these industry best practices. This function complements the existing grid operations functions and supports NDPP-focused operations. By staffing a dedicated NDPP resource in the grid operations center, the Companies have access to focused analysis related to NDPP that assesses the impacts of natural disasters on grid operations in real time. Based on common industry practices, an incremental hazard awareness resource is key to advancing and implementing NDPP projects and programs to harmonize with existing resources that do not have bandwidth to take on the additional workload associated with key NDPP functions.

The Companies plan to hire five Hazard Awareness Analysts to ensure the desk is staffed for 24-hour coverage. Education and experience for Hazard Awareness Analysts included a combination of wildland fire behavior, fire operation response expertise with weather behavior supplements. Hazard Awareness' core responsibility is to filter a wide range of intelligence from multiple sources to efficiently discern credible threats to the Companies' electric system and subsequently dispatch FMOs to engage in emergency operations coordinated to public safety incident commanders during emergency incidents.

Table 12 identifies the OMAG-related costs associated with the hazard awareness desk. There are no anticipated capital costs for this program.

Table 12. Proposed NDPP Hazard Awareness Desk

NV Energy - OMAG Proposed First Amendment Programs Hazard Awareness	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - OMAG	**0**	**0**	**703,808**	**703,808**	**703,808**
Risk Based Approach	**0**	**0**	**703,808**	**703,808**	**703,808**

Hazard Awareness	0	0	703,808	703,808	703,808
Sierra Pacific Power - OMAG	**0**	**0**	**1,055,712**	**1,055,712**	**1,055,712**
Risk Based Approach	**0**	**0**	**1,055,712**	**1,055,712**	**1,055,712**
Hazard Awareness	0	0	1,055,712	1,055,712	1,055,712
Grand Total	**0**	**0**	**1,759,520**	**1,759,520**	**1,759,520**

Distribution Automation: The Companies' System Protection department manages transmission protection down to the distribution feeder breaker. Currently, there is no dedicated team overseeing the automation and protection of the distribution network as a whole. Beyond the breaker, the regional engineers oversee distribution coordination on a limited and reactive basis for new protective devices such as reclosers, TripSavers, and fuses.

A dedicated Distribution Automation group within NDPP will address NDPP emergency response impacts by enabling "smart" devices that will be used to remotely control the system and reduce the number of customers and duration of NDPP-related outages. The distribution automation group will refresh outmoded protection on distribution circuits. Performing coordination studies on higher risk distribution circuits could potentially reduce fault clearing times to lower wildfire risk, improve the safety of field personnel, and significantly improve reliability.

During normal fire season, the Companies disable reclosing while maintaining delayed tripping to coordinate protective devices, with the assumption that the delayed tripping settings are correct. However, settings may not have been reviewed for several years. A distribution automation group within NDPP will review these settings.

Keeping pace with industry advancement offers additional mitigation opportunities through automation schemes, such as falling conductor detection and sensor technologies that may reduce the chance of igniting wildfires. These advancements also make the system more robust against other severe natural disasters, like heavy snowstorms with wet snow taking down sections of distribution network.

Approved resources would periodically conduct in-depth distribution coordination studies on all Tier circuits to reduce fault clearing times, enhance protective settings, and mitigate wildfire ignition risks on a prioritized basis. This provides the means to standardize other protection and automation technologies in elevated risk wildfire zones to minimize fire hazards to reduce response and troubleshooting time. Analysis informs the strategic placement of new line protective devices to promote reliability and reduce wildfire risks.

The distribution automation personnel will remotely control devices, like reclosers and smart fuses, to sectionalize circuit segments. Enabling this feature converts a dormant system to an intelligent one and reduces outages caused by PSOM, de-energization, or other NDPP activities. The distribution automation team will perform engineering studies and system analysis to assess the impact of potential proactive de-energization, identifying where proactive activations may cause larger (or longer duration) system outages than necessary. For those scenarios, engineers will use automation to enable remote operation and sectionalization during high-risk conditions. This will limit or eliminate the need for multiple truck rolls and delays associated with manual operation of system devices and equipment.

The NDPP distribution automation team will also be responsible for the field installation and maintenance of the installed automated devices. These activities include coordination to fire season settings enabling remote capability to trigger seasonal or fast trip enhanced settings when heightened fire risk conditions escalate.

The Companies propose onboarding an NDPP distribution automation leader and engineer during the latter part of 2025 to perform and complete studies for a small initial installation of Trip Savers and Interlocuters, including communications, during 2026. NV Energy then plans to onboard line personnel and a communication technician in early 2026 to meet the anticipated first wave implementation. During 2026, the team will complete analysis and engineering for a proposed expanded distribution automation plan intended for inclusion in the third triennial NDPP filed during 2026 commencing 2027 through 2029.

Table 13 and Table 14 show the proposed OMAG and capital budgets for distribution automation group within NDPP.

Table 13. Proposed NDPP Distribution Automation OMAG Budget

NV Energy - OMAG Proposed First Amendment Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - OMAG	**0**	**0**	**106,963**	**106,963**	**106,963**
Distribution Automation	0	0	106,963	106,963	106,963
Sierra Pacific Power - OMAG	**0**	**0**	**2,250,671**	**2,250,671**	**2,250,671**
Distribution Automation	0	0	2,250,671	2,250,671	2,250,671
Grand Total	**0**	**0**	**2,357,634**	**2,357,634**	**2,357,634**

Table 14. Proposed NDPP Distribution Automation Capital Budget

NV Energy - Capital Proposed First Amendment Programs	2024-2026 Approved Triennial Budget	2024-2026 Forecast	2024-2026 Forecast Incremental Labor	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - Capital	**0**	**0**	**35,654**	**35,654**	**35,654**
Distribution Automation	0	0	35,654	35,654	35,654
Sierra Pacific Power - Capital	**0**	**3,000,000**	**750,224**	**3,750,224**	**3,750,224**
Distribution Automation	0	3,000,000	750,224	3,750,224	3,750,224
Grand Total	**0**	**3,000,000**	**785,878**	**3,785,878**	**3,785,878**

2.4.2 Technology Plan

Technology has made a quantum leap since the NDPP was launched nearly five years ago. The industry has converged toward technologies that leverage advanced analytics, artificial intelligence, and increased computing capabilities. NV Energy has had success in using pilot programs to test the benefits, costs, and practicality of new technologies. The technology pilot programs requested for this First Amendment include:

AiDash Platform: AiDash offers a comprehensive vegetation management solution that begins with enhanced data gathering that leverages satellite imagery. Images are combined with other available information for advanced data analytics and processing. The predictive artificial intelligence ("AI") models use continuous learning to enhance the Companies' vegetation management initiatives. As a widely adopted industry tool, a pilot program would validate how vegetation management can be improved by efficiently deploying resources and reducing risk. Vegetation management is fundamental to reducing wildfire risk and an intelligent vegetation management system can lower risk, lessen the likelihood and impact of de-energization routines using the power of satellites and AI. The Companies are requesting $806,039 in 2025 and $2,268,961in 2026 for the AiDash pilot.

Palantir Foundry: Palantir Foundry is a wildfire data management platform for PSOM, Elevated Fire Risk ("EFR") and Fire Incident Tracking and Reporting ("FITR"). Palantir Foundry provides essential data integration, management and validation capabilities to reduce manual errors and processing delays for timely and accurate implementation of natural disaster mitigation operating programs.

Foundry will systematically collect, curate, transfer and analyze larger, interrelated, and dynamic wildfire-related datasets for reporting, internal and external communications, work tracking, and other workflows using dashboards and event management capabilities. The Companies propose four specific use cases for Palantir Foundry.

1. PSOM Customer Notifications;
2. Daily EFR Settings;
3. Fire Incident Tracking and Reporting; and
4. PSOM executive and external stakeholder post event reporting.

Palantir Foundry is an enhanced business intelligence tool. Palantir is the only known provider of mission-critical natural disaster risk mitigation information technologies with capabilities for PSOM event management, FTFM settings, and related data retention and reporting. Palantir Foundry provides essential data integration, management, and validation capabilities to reduce manual errors and processing delays for timely and accurate implementation of natural disaster mitigation operating programs.

Palantir will benefit the Companies' customers in Nevada though its capabilities of automatically creating customer notifications and data packages for sharing with the EWG partners, through improving customer notifications regarding PSOM events, and through integrating existing databases, eliminating the need for manual manipulation to improve the timeliness and accuracy of customer and EWG outreach. This will reduce operational planning and implementation errors and data loss. Over the longer run, data-driven information about fire and other natural disaster activity impact cause determination can uniquely benefit NDPP for continuous intelligent risk reduction. The Companies are seeking $786,380 in 2025 and $2,213,620 in 2026 for Palantir Foundry in OMAG.

The requested funding for AiDash and Palantir Foundry is shown in Table 15.

Table 15. NV Energy Emerging Technology and Strategies – AiDash Pilot Program and Palantir Foundry

NV Energy - OMAG Proposed First Amendment Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Labor	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)
Nevada Power - OMAG	**0**	**1,592,419**	**0**	**1,592,419**	**1,592,419**
Emerging Technologies and Strategies	**0**	**1,592,419**	**0**	1,592,419	1,592,419
AiDash	0	806,039	0	806,039	806,039
Palantir Foundry	0	786,380	0	786,380	786,380
Sierra Pacific Power - OMAG	**0**	**4,482,581**	**0**	**4,482,581**	**4,482,581**
Emerging Technologies and Strategies	**0**	**4,482,581**	**0**	4,482,581	4,482,581
AiDash	0	2,268,961	0	2,268,961	2,268,961
Palantir Foundry	0	2,213,620	0	2,213,620	2,213,620
Grand Total	**0**	**6,075,000**	**0**	**6,075,000**	**6,075,000**

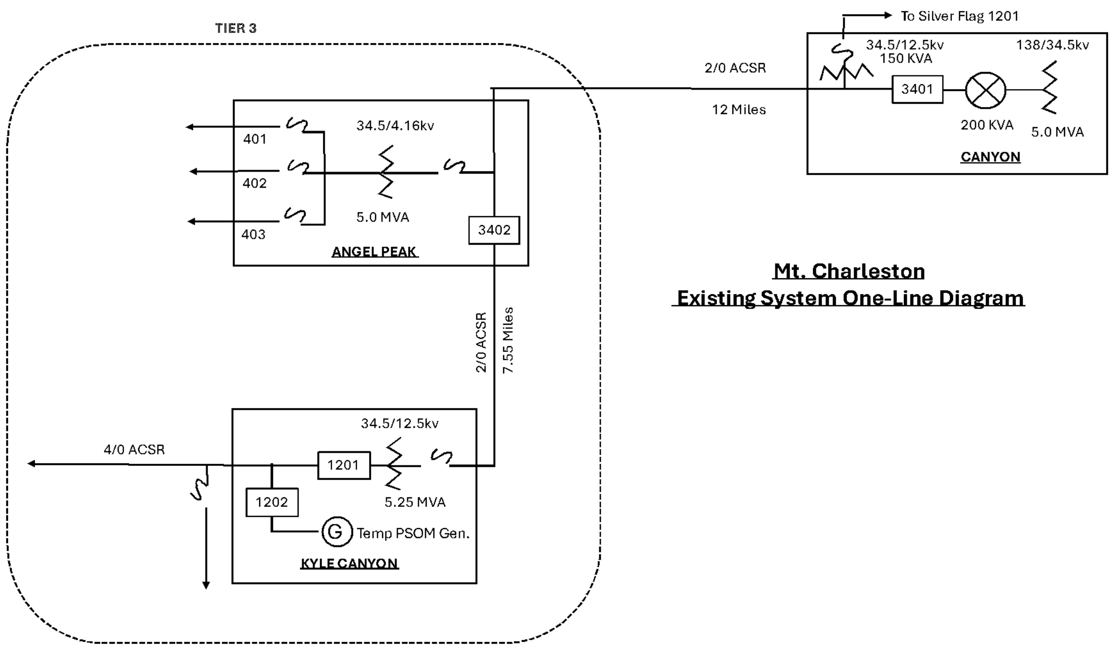
2.5 Mt. Charleston Rebuild

Mt. Charleston's Tier 3 ranking results from environmental conditions combined with the lack of evacuation routes. Mt. Charleston's distribution system has experienced extreme damage in Tier 3 from catastrophic weather events, including 2023's Hurricane Hilary. NV Energy originally requested $73,750,000 for the comprehensive rebuild of the Mt. Charleston system. In Docket No. 23-03003, the

Commission approved approximately $15.9 million for Mt. Charleston rebuild in the Plan for years 2024 to 2026.

In its current configuration, shown in Figure 2, NV Energy seasonally deploys a diesel generator at Kyle Canyon substation for service continuity during PSOM events. The operational measures for the short- and medium-term wildfire mitigation include PSOM.

Figure 2. Mt. Charleston Current Configuration



Since approval of the initial mitigation plan for Mt. Charleston, the Companies have evaluated alternative solutions to reduce wildfire risk during extreme fire weather and to lower the likelihood of PSOM for the area. The system hardening activities evaluated included undergrounding sections of circuits, installing ductile iron in place of wood poles, and utilizing covered conductor. A complete account of alternatives considered is included in Appendix C. Results of this evaluation indicate that a clean energy microgrid and Tier 3 construction standards for Mt. Charleston would reduce the risk of wildfire ignition and lower the likelihood of PSOM at a lower projected cost.

The reconfigured rebuild of the Mt. Charleston system still entails four phases, estimated at $52,892,220, shown in Table 16.

2.5.1 Phase 1 Amended Request: Develop and Install a Clean Energy Microgrid

For historical reference, in its original Phase 1 Northwest 1215 to Kyle Canyon 1201, NV Energy assessed the configuration of the existing electric system serving Mt. Charleston and determined that, in addition to the Angel Peak improvements, a new distribution feeder should be built to serve the Kyle Canyon community from Northwest substation. The new distribution feeder, Northwest 1215, would enable the removal of the Kyle Canyon substation and the Angel Peak 34 kV 3402 circuit to significantly reduce the fire risk associated with these vulnerable facilities. Furthermore, having a new power source for Kyle Canyon residents, which is separate from Angel Peak, would reduce the frequency of PSOM events for Kyle Canyon. The prior estimated costs included the construction of the new Northwest 1215 feeder tie with Kyle Canyon 1201 located in Tier 3. The total estimated cost for the Phase 1 Northwest

1215 to Kyle Canyon Feeder Tie was approximately $60 Million and the total original project estimate was $73,750,000.

Based on the new approach presented in this First Amendment, NV Energy is requesting funding for the revised Phase 1 to procure and implement a permanent fire season activated microgrid using a combination of solar PV generation, a battery energy storage system ("BESS"), and propane generation resulting in a 50 percent renewable profile. NV Energy also requests funding to complete conforming Tier 3 system ruggedization and protection upgrades for Kyle Canyon to Angel Peak circuits.

As shown in Table 16, NV Energy requests an additional $3,175,000 above the approved amount to implement Phase 1, for a total of $19,075,000 million through 2026, that includes $1.75 million to complete the conversion to Tier 3 standards, including FTFM. Based on successful deployment of the microgrid, a future budget request may include an option to expand into year-round microgrid operation for an 80 percent renewable profile.

2.5.2 Phase 2 from the 2024-2026 NDPP Request: Ruggedize the Kyle Canyon 1201 Feeder (Unchanged)

Once the microgrid is in place, the Companies propose to bring the Kyle Canyon 1201 feeder up to wildfire ruggedized standards for Tier 3. The circuit would be rebuilt using covered conductor. NV Energy requires ductile iron structures for any overhead poles that are built within Tier 3 where line truck access is possible. Poles in less accessible areas will be constructed using fire-wrapped wood poles. NV Energy will use approved funding for design and permitting, estimated at $120,000 in 2025 and $130,000 in 2026. The total estimated cost to rebuild the Kyle Canyon 1201 circuit is approximately $11.5 million, which will be requested in a future filing, most likely in the next triennial NDPP.

2.5.3 Phase 3 Amended Request: Ruggedize the Kyle Canyon Substation and Angel Peak 3402 Feeder

The Companies will request funding to bring the Kyle Canyon substation and Angel Peak 3402 lines up to Tier 3 ruggedized standards. The Companies will provide necessary civil site improvements for proper draining, retaining walls, and other improvements as needed to protect it from natural disasters. The circuit would be rebuilt using covered conductor specifications. NV Energy would use ductile iron structures for any overhead poles that are built within Tier 3 where accessible by line truck. Poles in less accessible areas will be constructed using fire-wrapped wood poles. NV Energy will use approved funding for design and permitting for rebuilding Kyle Canyon substation and Angel Peak 3402, estimated at $120,000 in 2025 and $130,000 in 2026. The total estimated cost to rebuild Kyle Canyon substation and Angel Peak 3402 is approximately $13.8 million, which will be requested in a future filing, most likely in the next triennial NDPP.

This Phase 3 Amendment request replaces the original request in the 2024-2026 NDPP to remove Kyle Canyon substation and Angel Peak 3402 line, as the feeder tie to convert the system to 12 kV is no longer needed based on the microgrid.

2.5.4 Phase Four: Canyon 3401 Rebuild from the 2024-2026 NDPP Request (Unchanged)

Approximately one mile of Canyon 3401 is in Tier 3. The Companies propose to bring the Canyon 3401 line up to Tier 3 standards. The circuit would be rebuilt using covered conductor and ductile iron poles where there is line truck access. Less accessible areas would use fire-wrapped wood poles. NV Energy is using approved funding for design and permitting of Phase 4, estimated at $35,000 for 2025 and $40,000 for 2026. The estimated cost to rebuild one mile of Canyon 3401 in Tier 3 is approximately $2 million. A Phase 4 request for construction funding will be included in a future filing, most likely the next triennial NDPP.

The Companies anticipate that the extensive permitting constraints and the difficult to access roadways have the potential to create project delays. Bureau of Land Management ("BLM"), Red Rock Canyon National Conservation Area ("RRCNCA"), Nevada Department of Transportation ("NDOT") and United States Forest Service ("USFS") permits are all required for the alternatives, which can take several years for approval depending on the environmental impact study. Furthermore, the RRCNCA has not allowed new permitting in the area since the original power lines were built so there is a risk no new permits would be allowed.

A full representation is shown in Figure 3, and the rebuild by phase is shown in Figure 4. Full project details are included for completeness.

Figure 3. Mt. Charleston Four Phase Plan

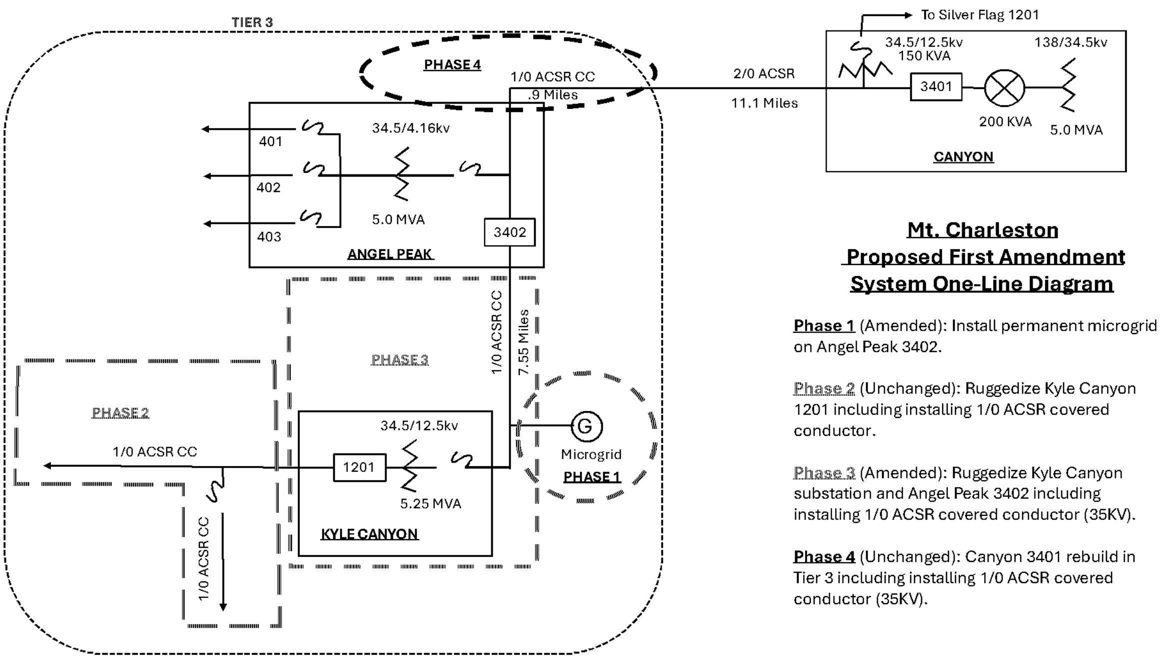
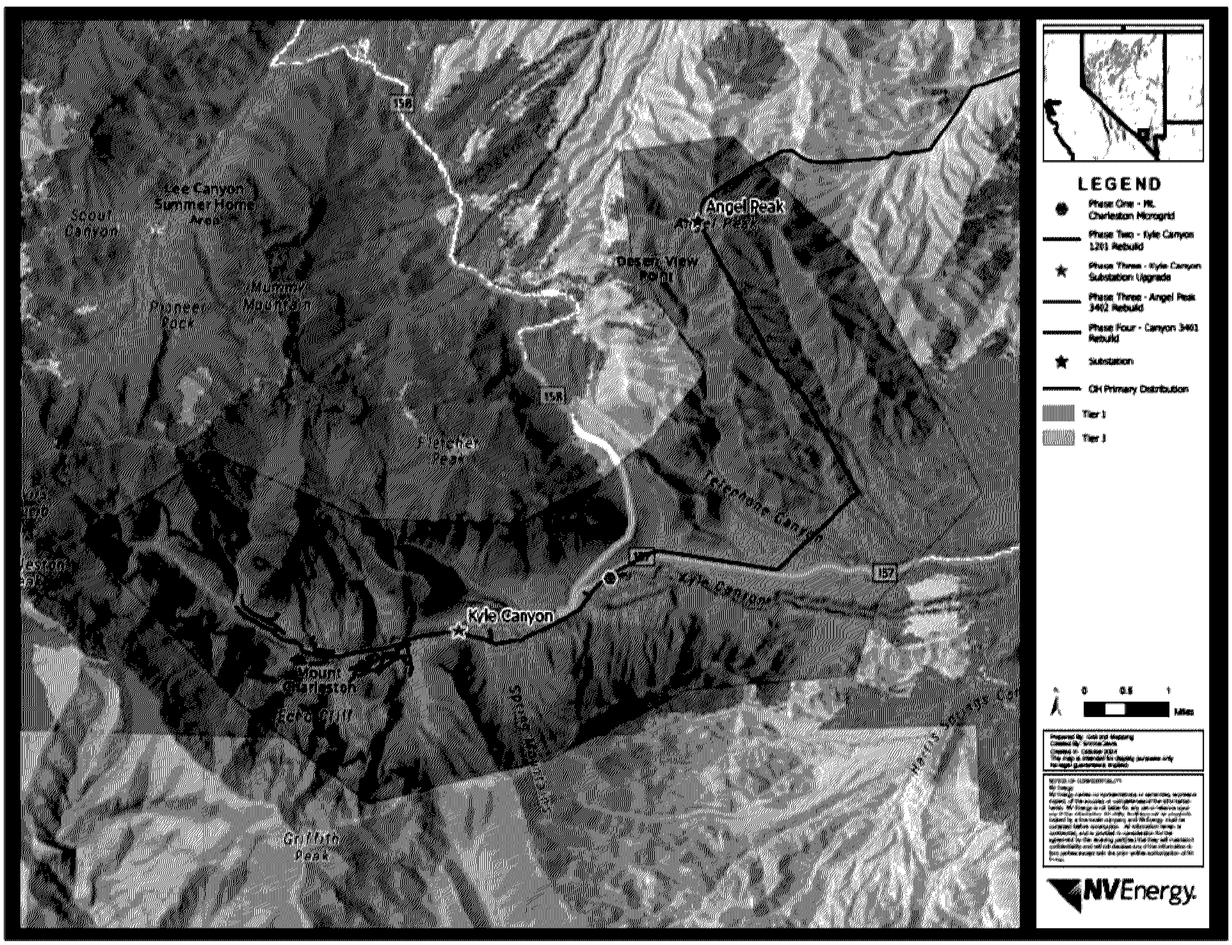


Table 16. Mt. Charleston Rebuild

Nevada Power - Capital Currently Approved NDPP Programs	2024-2026 Approved Triennial Budget	2024-2026 Current Forecast	2024-2026 Forecast Incremental Mt Charleston Labor	Total 2024-2026 First Amendment Forecast	Total First Amendment Request Increase / (Reduction)	2027-2029 Forecast	Total 2024-2029 Project Forecasts
System Hardening	**15,906,102**	**19,075,000**	**342,220**	**19,417,220**	**3,511,118**	**33,475,000**	**52,892,220**
Distribution Line Rebuilds	**15,906,102**	**19,075,000**	**342,220**	**19,417,220**	**3,511,118**	**33,475,000**	**52,892,220**
Phase One - Mt. Charleston Microgrid	15,331,102	18,500,000	342,220	18,842,220	3,511,118	6,750,000	6,750,000
Phase Two - Rebuild Kyle Canyon 1201 Feeder	250,000	250,000	0	250,000	0	11,250,000	11,250,000
Phase Three - Rebuild Kyle Canyon Sub & AP3402	250,000	250,000	0	250,000	0	13,550,000	13,550,000
Phase Four - Rebuild Canyon 3401 in Tier 3	75,000	75,000	0	75,000	0	1,925,000	1,925,000
Grand Total	**15,906,102**	**19,075,000**	**342,220**	**19,417,220**	**3,511,118**	**33,475,000**	**52,892,220**

Figure 4. Mt. Charleston Rebuild Project



2.5.5 Overall Mt. Charleston Rebuild Comprehensive Budget

While NV Energy is not requesting the comprehensive budget in this First Amendment, the following informational budget is included in Table 17. Mt. Charleston Rebuild Comprehensive Budget for the Commission's review. Table 17 also compares the original estimate and the proposed changes for each phase.

Table 17. Mt. Charleston Rebuild Comprehensive Budget

Nevada Power	Original Estimate	Amended Budget	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Original Phase 1 – Feeder Tie NW 1215/KC 1201	$60,000,000						
First Amendment Phase 1 – Mt. Charleston Microgrid		**$25,250,000**	$3,771,110	$15,071,110	$6,750,000	X	X
Phase 2 – Rebuild Kyle Canyon 1201 Feeder (unmodified)	$11,500,000	**$11,500,000**	$120,000	$130,000	$8,250,000	$3,000,000	X
Original: Phase 3 – remove Kyle Canyon Substation and Angle Peak 3402	$250,000						
Update: Phase 3 – Rebuild Kyle Canyon Sub & AP3402		**$13,800,000**	$120,000	$130,000	$3,750,000	$9,800,000	X
Phase 4 – Rebuild CN3401 In Tier 3 (Unmodified)	$2,000,000	**$2,000,000**	$35,000	$40,000	$50,000	$275,000	$1,600,000
Total Original Budget	$73,750,000						
Total Mt. Charleston Revised Budget		**$52,550,000**	$4,046,110	$15,371,110	$18,800,000	$13,075,000	$1,600,000

2.6 Grant Funding Negotiations

The Companies have been invited by the DOE to enter into negotiations as a subawardee of a GRIP grant under the awardee, E Source.[12] This potential supplemental funding is anticipated for the Mt. Charleston area with a microgrid and advanced technologies. The Companies' opportunity for funding

[12] https://www.energy.gov/sites/default/files/2024-10/ESource_GRIP2_Fact_Sheet.pdf.

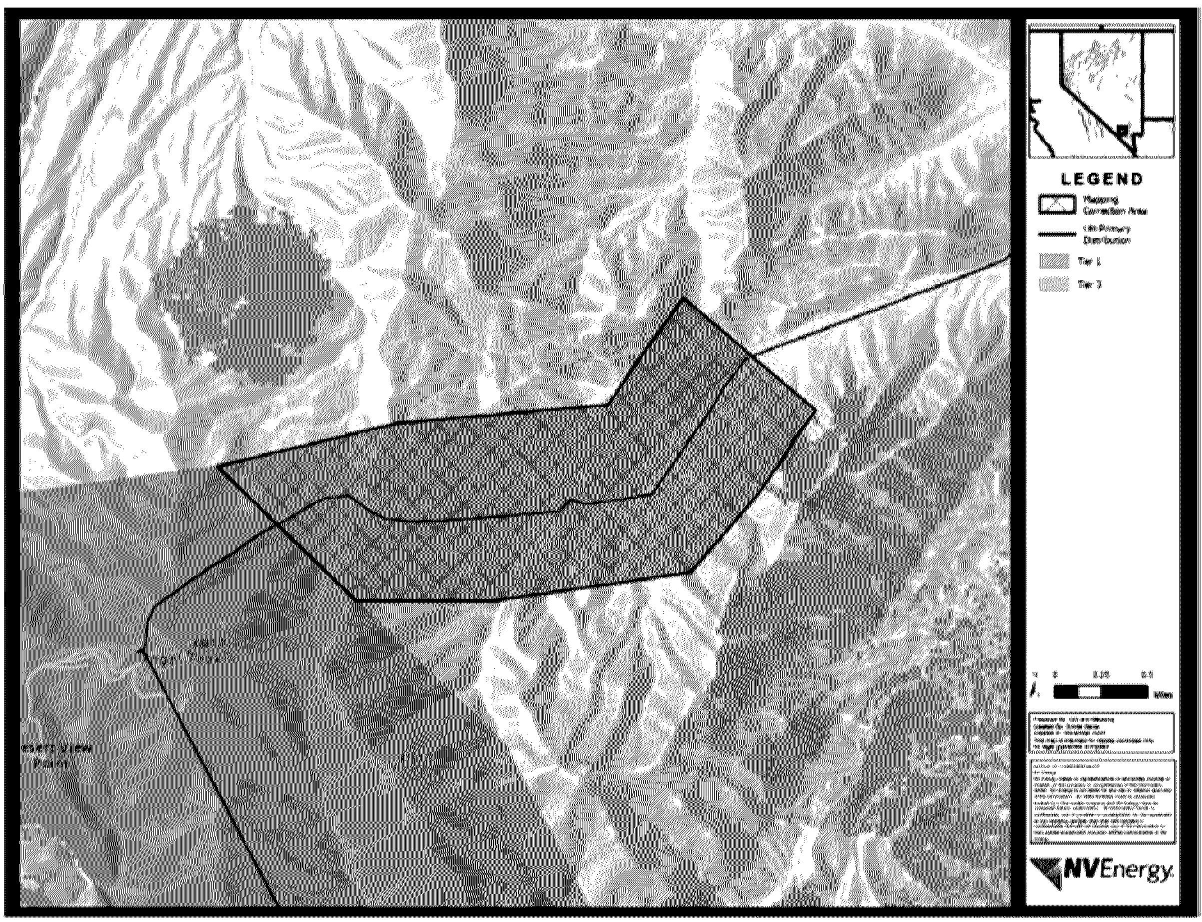
advances leading grid resilience concepts and innovative technologies, extending across a 60-month window, which exceeds the current NDPP timeframe. Once negotiations are complete, the Companies will provide further information as to the final scope, approach, and application of match funding for the grant. While grant funding will go a long way to supporting key resilience initiatives and advanced technology, it also demands a heightened level of tracking and reporting, as well as robust community engagement. The need for additional oversight aligns with the Companies' First Amendment labor resource plan request.

2.7 Mapping Corrections

The Companies have identified a need to correct gaps in fire Tiers for two circuits resulting from a GIS anomaly. The gaps were identified along the Tier 3 areas of Mt. Charleston for Nevada Power and Lake Tahoe for Sierra. While the circuits are continuous circuits, the maps showed them as non-continuous.

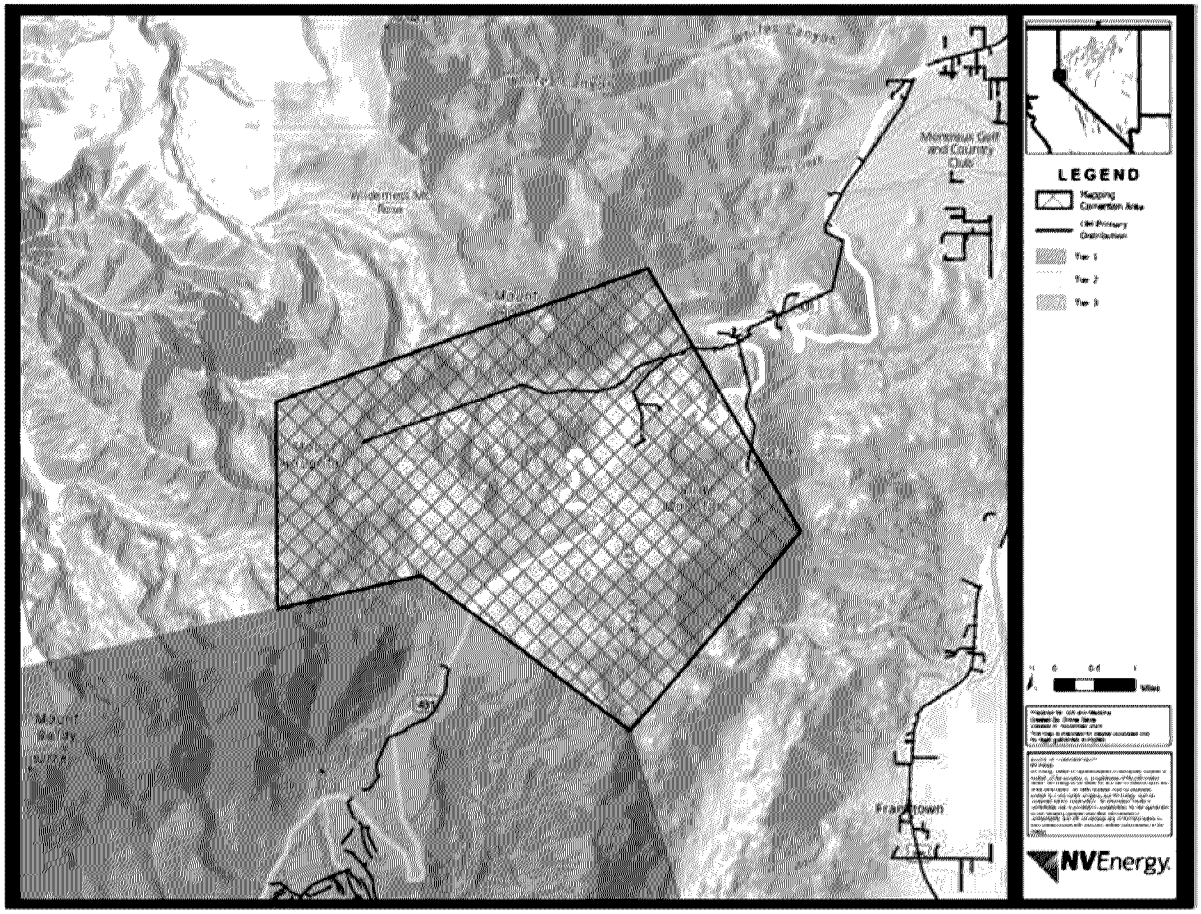
The map for Mt. Charleson is shown in Figure 5 for the Canyon 3401 distribution circuit that clarifies the Tier 1 boundary to add 2.4 line miles and 35 poles.

Figure 5. Mt. Charleston Area Map Correction



The map for the Lake Tahoe area of Sierra includes the Steamboat 212 distribution circuit, shown in Figure 6, that clarifies the Tier 2 boundary to add 4-line miles and 96 poles.

Figure 6. Lake Tahoe Area Map Correction



Appendix A: July 2024 Informational Update Docket No. 24-07003

This section contains the previously filed 2024 summer readiness informational update.

Natural Disaster Protection Plan Progress Report

Enhanced Fire Season Protocols

Informational Update

NVEnergy®

2024 Natural Disaster Protection Plan Enhanced Fire Season Protocols
July 3, 2024

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1 Executive Summary

Pursuant to Nevada Revised Statute ("NRS") 704.7983 and Section ten of the regulations approved by the Public Utilities Commission of Nevada (the "Commission") in Docket No. 19-06009, filed with the Secretary of State by the Legislative Council Bureau ("LCB") on February 27, 2020, in LCB File No. R085-19 (the "Regulations"), Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") are required to file on or before September 1 of the first and second years after submittal of a natural disaster protection plan a progress report concerning the Natural Disaster Protection Plan ("NDPP" or "Plan") that will apply to each year remaining for the period covered by the NDPP.

This progress report is an informational update to fire season operating practices. Fire season risk mitigation includes the Public Safety Outage Management ("PSOM") Plan, enhanced seasonal protection settings and reclosers, and de-energizing portions of the distribution and transmission system when those areas present a potential threat to public safety in cases of an active wildfire threat. This update covers threshold criteria for these updated fire mitigation measures, procedures to restore power to the system, and considers impacts for critical responders, and customer, stakeholder, and communication provider notification.

The Companies present this informational update to apprise the Commission of the Companies' intent to implement these procedures system-wide commencing immediately for the 2024 fire season. The Companies will provide an additional fire season update including PSOM events, implementation of enhanced fast curve settings, and implementation of an emergency de-energization wildfire policy in the 2024 NDPP Progress Report that the Companies will file on or before September 1, 2024. Additionally, the Companies are preparing a formal amendment to the NDPP to be filed in the coming months to further address the enhanced fire season protocols. Implementation of these measures is time-critical to meet the current fire season risk. The Companies will seek recovery of the costs associated with the enhanced safety measures discussed here, such as implementation of fast curve settings and acceleration of TripSavers, in a future general rate case proceeding.

2 Background

As the frequency and severity of wildfires and extreme weather events increase, the implementation of rigorous protocols for proactive de-energization have become the industry standard for safety when extreme conditions present risk to public safety. PSOM is a critical measure to swiftly address an imminent wildfire anywhere on the electric system. However, PSOM cannot be viewed in isolation but as part of a multifaceted natural disaster mitigation strategy embodied in the Companies' NDPP.

The state of Nevada's Research Division of the Legislative Counsel Bureau produced an overview of Nevada wildfires that it described as "especially devastating wildfires" in recent years which were driven in part by "[y]ears of unusually dry conditions and the spread of invasive plants like cheatgrass…"[1] From 1980 to 1999, 4.2 million acres burned in neighboring states.[2] From 2000 to 2018 that value more than doubled to 9.5 million acres.[3]

Since then, Nevada has experienced significant fire seasons, notably in 2020 and 2021, with major fires in western Nevada. These include the Numbers and Pinehaven Fires in 2020, and the Tamarack and

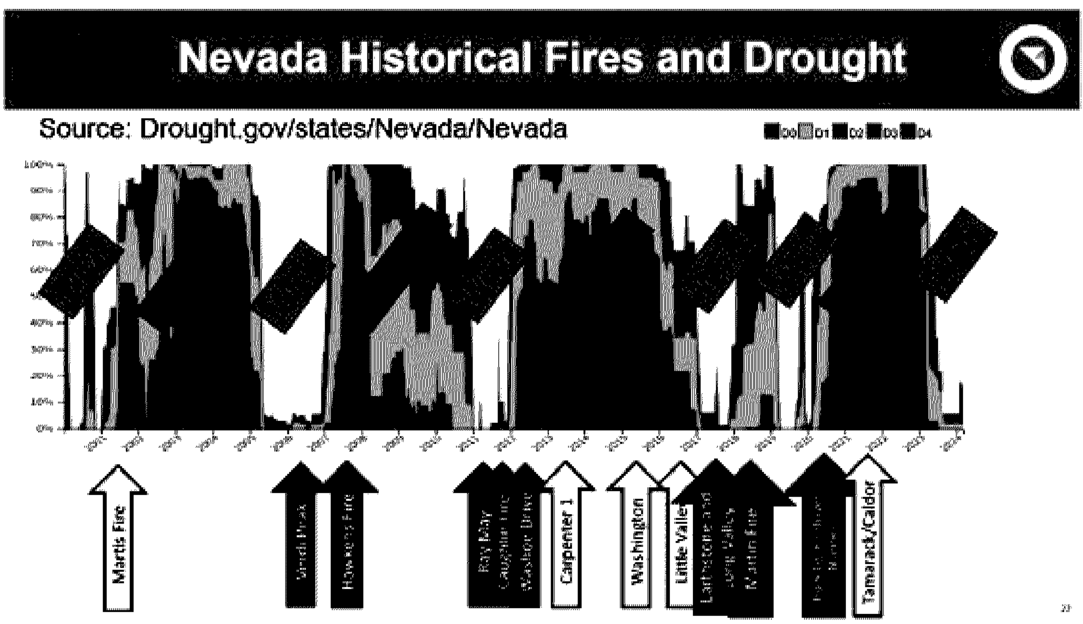
[1] Stinnesbeck, Jann, "Wildfires in Nevada: an Overview," https://www.leg.state.nv.us/Division/Research/Documents/Wildfires-in-Nevada-2020-FINAL.pdf, January 2020.
[2] Id.
[3] Id.

Caldor Fires of 2021. For the years 2022 and 2023 Nevada experienced milder fire seasons due to wetter than normal conditions.

Western states have made considerable progress using technology-based decisions and updating protocols as wildfire resilience plans are refined and implemented. Communities have benefited from reduced risk in areas where significant mitigation work is complete. The areas benefiting from this focus are prioritized based on a forecast of highest risk. However, catastrophic wildfires are now occurring in areas not previously identified as at-risk. The new trend of catastrophic fires occurring in non-high-risk areas has expanded well beyond west coast states. Unexpected catastrophic fires have occurred in Colorado and Oregon, and more recently in Hawaii, Canada, and Texas. Interest in implementing proactive de-energization protocols is spreading among other utilities in the country's eastern half. States such as Pennsylvania, Kentucky, and Rhode Island have put de-energization protocols in place despite their relatively low wildfire risk service territory.

Projections for the 2024 fire season indicate above normal wildfire potential for portions of the State, with greater risk than the past two fire seasons. Nevada's own history of major fires shows a pattern of wildfires occurring following extended wet winter seasons. The fire risk for 2024 will be greater than average, and certainly a greater risk than the last two quiet fire seasons as shown in Figure 1.

Figure 1: Major Fires Relative to Wet Season



2024 projections for above normal fire risk point to areas around the Spring Mountains/Red Rock area of southern Nevada, beginning in June 2024, and the valleys of northern Nevada beginning in the July/August 2024 timeframe. Recent wet winters contributed to above normal grass loading in these areas. Combined with expected hotter and drier conditions this summer, the likely result is increased wildfire activity. In fact, the Companies filed notices for eleven wildfires in June 2024, which is more reportable wildfires than occurred in 2022 and 2023 combined.[4] Overall, total fire ignitions for Nevada are

[4] See the various wildfire notices filed in Docket No. 24-01013, Docket No. 23-01013 and Docket No. 22-01013.

double when compared to the number of fire ignitions that occurred during 2023.[5] Given these threat conditions for the summer 2024 operating season, it is imperative that the Companies take timely mitigation steps to decrease this risk level. This includes preparing the Companies and communities for emergency de-energization protocols when extreme risk conditions are present anywhere on the overhead electric system.

3 Summer 2024 Preparedness Initiatives

The following section summarizes the updated preparedness measures for the summer 2024 wildfire season. Full implementation of these measures represents the Companies' enhanced fire season protocols going forward.

3.1 Proactive De-energization: Public Safety Outage Management

The PSOM program was initiated as part of the inaugural NDPP risk mitigation measures. PSOM has previously been limited to Tiers 3, 2, and 1E, representing less than 10% of the Companies' overhead system. This left over 90% of the overhead system, including the Commission-approved Tier 1,[6] without the protection of this structured mitigation measure when wildfire risk conditions are present.

3.1.1 *Composite Risk Index*

Beginning in 2021, a Composite Risk Index ("CRI")[7] valuation tool formed the basis for the Companies' risk-based approach. CRI is an effective and proven approach to analyzing conditions for proactive circuit outages when conditions pose a significant threat to the Companies' customers, infrastructure, or the public. PSOM processes are activated when conditions exist that create unacceptable risk that electric infrastructure could either become a source of ignition or could perpetuate a wildfire. NV Energy's PSOM Plan, including criteria thresholds, mitigation measures terminology, and protocols, was presented in the triennial update to the NDPP Expanded PSOM.

Because of more frequent catastrophic conditions that do not precisely align with the defined boundaries of the Wildfire Risk Tiers, NV Energy is extending PSOM across its service territories. The decision to extend PSOM procedures system-wide represents a significant advancement to bolster grid resilience in the face of escalating wildfire risk. By broadening PSOM policies to encompass all of NV Energy's service areas, the Companies may swiftly respond to wildfire threats for the safety of their customers, employees, and communities. Expanding PSOM beyond Tier 3, 2 and 1E picks up the remaining 90% of the overhead system consisting of 15,000 miles[8] that were previously unaddressed by any type of wildfire mitigation. Extending PSOM coverage to 100% of the overhead system ensures that any area vulnerable to wildfires within NV Energy's service territories can be monitored and protected by proactively de-energizing any part of the system when the high threat criteria are reached.

By identifying and de-energizing power lines that are subjected to extreme fire weather conditions, NV Energy can better mitigate the risk of wildfires being caused or perpetuated by energized electric infrastructure contributing to overall wildfire prevention and public safety efforts.

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[5] National Interagency Fire Center. www.nifc.gov. June 2024

[6] Docket No. 23-03003. Order dated August 28, 2023, at paragraph 26, p. 13.

[7] The CRI initially appears in testimony of Langdon-DIRECT in Docket No. 21-03040 and Docket No. 23-03003 NDPP Annual Plan, Volume 2 Appendix C, at p. 6, March 1, 2023.

[8] This informational update does not propose a change to the wildfire Risk Tiers approved in Docket No. 23-03003, as the Tiers apply across a variety of NDPP projects and programs.

Historical actual weather events indicate PSOM criteria for the expanded areas is expected to be met infrequently, and only during the most extreme fire weather events. Since the CRI-based PSOM criteria were implemented in 2021, there have been zero days that PSOM would have been implemented in Tier 1E or lower in Nevada. The Companies currently use Cloudfire[9] dashboards for situational awareness and will expand this capability to the new areas described in this special progress report.

Over the longer term, expanding the PSOM area will also require new weather stations and fire cameras to further refine and improve situational awareness in these areas, as well as add precision to data-driven decision making in the future. Additional technology for areas extending beyond Tier 3, 2, and 1E are being evaluated for future consideration.

The Companies will follow the same communication and coordination plans included in the refreshed PSOM Plan, provided in Appendix A. The Companies continue to collaborate with first responders and other critical service providers supports effective wildfire mitigation and response.

A key change to the expansion of PSOM is the ability to de-energize more efficiently through automated devices when possible or a single manual field point. Using automated devices or a single manual field point may initially de-energize a larger selection of customers that, once a situational assessment has been completed, will be re-energized. This change results in a faster action with less reliance on field resources to manually operate multiple devices.

Alternatives Considered to Expanding PSOM

The risks associated with not expanding PSOM and related monitoring to all of the Companies' overhead system could result in potential for a utility related ignition that may otherwise be avoided by activating PSOM during extreme weather. This is especially important in the face of more frequent and extreme weather resulting from climate change, as evidenced in significant wildfires in recent years in California, Colorado, Hawaii, Texas and Oregon. Public safety concerns include the potential for increased property damage, including destruction of structures, infrastructure, evacuations, injuries, and loss of life in extreme events. Environmental impacts include habitat destruction and loss of livestock and wildlife. The economic costs associated with firefighting efforts, property damage, and loss of revenue from disrupted businesses could be substantial, impacting both individuals and the broader economy.

3.2 Enhancements to Fire Season Mode for Tier 3, 2, and 1E – Fast Trip Fire Mode

To further reduce the chance of accidental ignition during periods of high wildfire risk, the Companies are enhancing fire weather system protection settings for Tier 3, 2, and 1E. Implementation of these Fire Mode settings provides an added layer of resilience on high-risk days during fire season and offers an industry-adopted alternative to PSOM. As a leading industry practice, Fast Trip Fire Mode ("FTFM") includes disabling automatic reclosers under high-risk conditions and replacing expulsion fuses with current-limiting fuses or electronic fuses. FTFM results in a near-instantaneous trip when a fault occurs. In California, fast acting fuses that interrupt electrical current have been installed to reduce ignition risk. A growing number of utilities outside of California have also adopted these condition-based de-energizing capabilities, increasing the sensitivity of protective devices and equipment under extreme conditions to rapidly disconnect when a fault is detected.

In 2023, the Companies implemented FTFM for the Tier 3 areas of Lake Tahoe and Mt. Charleston. FTFM efforts were not charged to the NDPP regulatory asset. The Companies are now expanding FTFM to Tier 2 and Tier 1E, subsequently enabling fast trip on nearly 10% of the overhead system by 2026. As

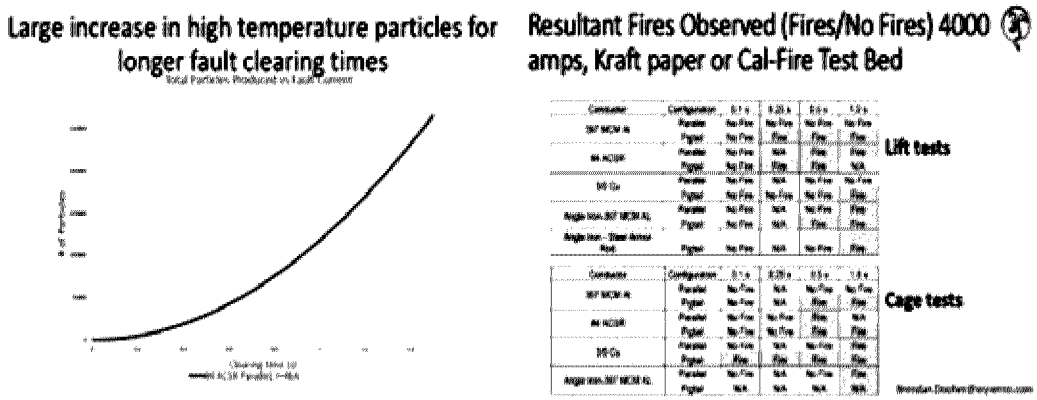
[9] Formerly REAX Engineering.

part of implementation of FTFM in Tier 2 and Tier 1E, the Companies first assessed 160 substation circuit breakers and line reclosers to identify the devices that would require FTFM. This formed the baseline for determining capabilities of the existing equipment and identified required improvements. In total, 152 devices require FTFM; 56% of the devices are fully capable of FTFM, 19% have hot line tag ("HLT")[10] capabilities that can be utilized in the short term for FTFM, and 25% have no capability. During 2024, the Companies will implement 75% of the Tier 2 and Tier 1E devices by completing relay setting changes on the 85 circuit breakers and line reclosers that are fully FTFM capable and will temporarily rely on HLT mode for 29 circuit breakers. The overall Tier 2 and Tier 1E FTFM implementation percentage for 2024 could be higher as relay and line recloser replacements are completed.

During Tier 3 implementation, a key strategy to minimize outage impacts of FTFM was utilizing the fast trip capabilities of the TripSavers. This same strategy will be used for FTFM implementation in Tier 2 and Tier 1E. The Second Triennial NDPP approved in Docket No. 23-03003 anticipates replacement of 1,200 expulsion fuses with TripSavers in Tier 2 and Tier 1E at an approved capital cost of $12.8 million. An additional 1,400 TripSaver installations are anticipated for 2027-2029, to complete the NDPP expulsion fuse replacement program as planned for Tier 3, 2, and 1E. Given the 2026 target to meet 100% FTFM in Tiers 3, 2, and 1E, the Companies now intend to accelerate the replacement of select expulsion fuses with TripSavers that were initially planned for 2027-2029. The acceleration focuses on fuse replacements where TripSavers will be installed on select mainlines only. The Companies' acceleration of approximately 470 TripSavers is estimated at $5 million. This acceleration of select TripSavers is critical to implementing FTFM because TripSavers can reduce the impact of downstream outages through improved ability to isolate faults. Select TripSaver acceleration is being performed as a regular business expense and the Companies will seek recovery in a future general rate case.

Changing the operating mode for substation circuit breakers and line reclosers is a critical implementation step for FTFM. FTFM is supported by industry research and laboratory testing to reduce faults that expel hot particles or sparks that could be the source of an ignition. As depicted in Figure 2, risk is significantly reduced when fault clearing time, the time it takes a breaker to trip open, is limited to about 0.1 seconds.

Figure 2. Faster Fault Clearing Times Reduces Risk



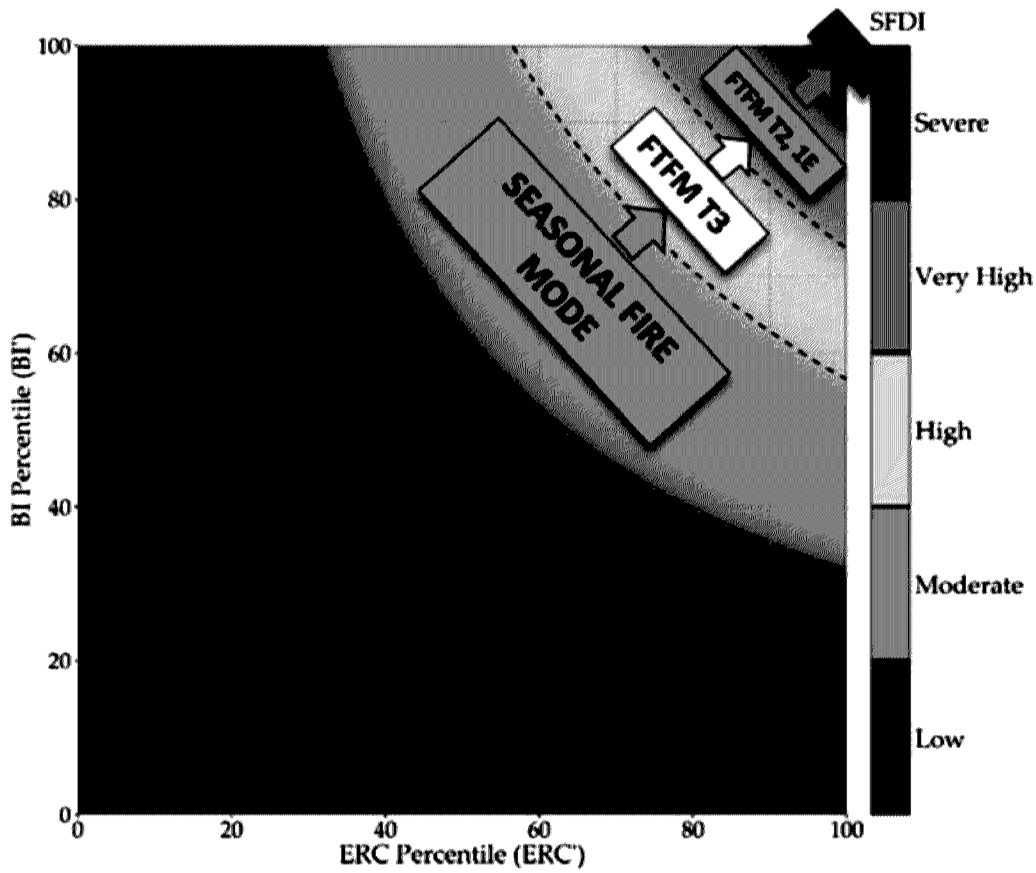
Source: 2020 Pacific Gas and Electric Company ("PG&E") Presentation: Assessment of Hot and Flaming Particles and Fire Risk from High Current Faults

[10] Also called no-reclose capability.

By leveraging FTFM on specific days, NV Energy can enhance fire season operating procedures that mitigate the risk of an equipment caused ignition, reserving PSOM for the most extreme conditions. The following excerpt is from the FTFM section that was added to NV Energy's NDPP Wildfire Season Operations Plan.

Typically, after NV Energy has entered Fire Season Mode, when the Severe Fire Danger increases to high or very high levels, circuits in the Proactive De-energization Zones ("PDZ") can be placed into FTFM as an enhanced level of protection against potential wildfire ignitions. This setting is enabled when the Severe Fire Danger Index ("SFDI") rises to "High", "Very High", or "Severe" for Tier 3 areas, and "Very High" or "Severe" levels for Tier 2/1E/1 PDZ areas. (https://nvfireweather.com/forecast/) represented in Figure 3.

Figure 3. Fast Trip Fire Mode Based On Severe Fire Danger Index



Source: NV Energy's NDPP Wildfire Season Operations Plan

NV Energy's meteorologist monitors these conditions daily and notifies system control, lines department, and substation leadership of approaching conditions. System control remotely changes system settings *into FTFM, if capable, or requests a field setting change during severe fire weather conditions.[11] Industry publications filed with the California Public Utilities Commission provide comparative results of FTFM. Appendix B references two reports prepared by PG&E in 2022 titled 1) Utility Benchmarking of Fast Trip Schemes and Relay Technologies for Fire Mitigation[12] and 2) Fast Trip Settings: California Investor-Owned Utilities Comparison.[13]*

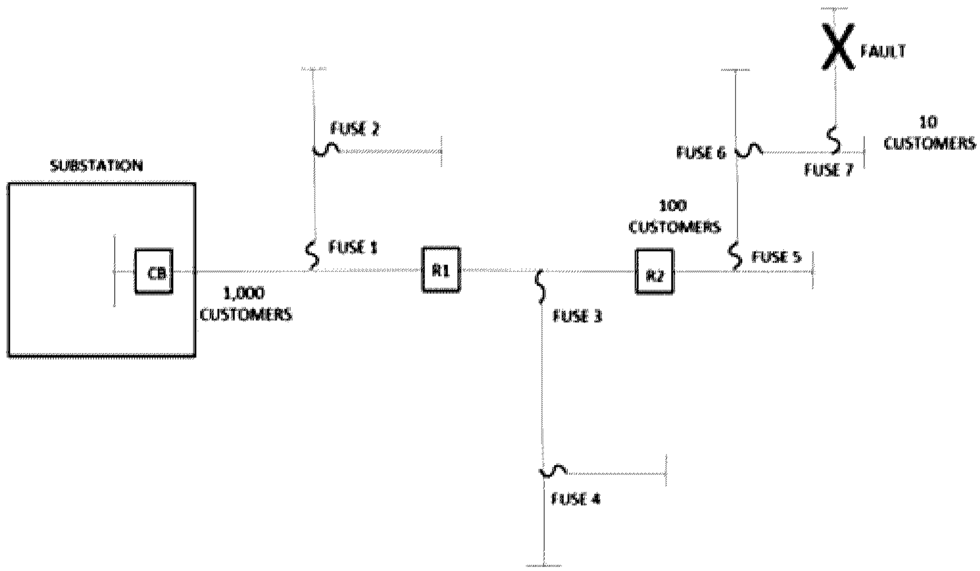
Appendix C provides NV Energy's "Modes of Operation for Substation Breakers and Line Reclosers on Overhead Distribution Circuits." It describes the five modes of operation: 1) Auto; 2) Manual; 3) HLT; 4) Seasonal Fire Mode; and 5) FTFM. When FTFM is enabled on a substation breaker or line recloser, the settings of the protective relays are modified to disable reclosing to effectuate instantaneous tripping with a 0.1 second delay. FTFM further reduces risk when combined with seasonal Fire Mode where single shot reclosing occurs with normal speed tripping. This mitigation approach comes with a tradeoff. Unlike seasonal fire mode, when a device has FTFM enabled, downstream coordination with other protective devices such as line reclosers and fuses are disabled. So, when a fault occurs, the resulting outage can affect more customers and last longer. To illustrate the reliability impacts, consider the system shown below in Figure 4. In this figure, there is a substation circuit breaker ("CB"), two mainline line reclosers (R1, R2), and multiple fused laterals (Fuse 1 - Fuse 7). There are 1,000 customers on the circuit with ten of them downstream from Fuse 7, where a fault is shown.

[11] FTFM is common industry practice that is comparable to programs such as PG&E's "Enhanced Power System Settings ("EPSS"), SCE's "Fast Curve" ("FC") Settings, San Diego Gas & Electric Company's ("SDG&E") "Sensitive Relay Profile" ("SRP") and PacifiCorp's "Sophisticated Program Control Settings" ("SPCS").

[12] https://www.bing.com/ck/a?!&&p=1974d5f86f07023cJmltdHM9MTcxNTgxNzYwMCZpZ3VpZD0wYjRmMDQ3Ny0wYmJiLTY2MzAtMjY4Yy0xNmI5MGE0MDY3Y2UmaW5zaWQ9NTE5OA&ptn=3&ver=2&hsh=3&fclid=0b4f0477-0bbb-6630-268c-16b90a4067ce&psq=Utility+Benchmarking+of+Fast+Trip+Schemes+and+Relay+Technologies+for+Fire+Mitigation%3b+and+2)+Fast+Trip+Settings%3a+California+IOU+Comparison&u=a1aHR0cHM6Ly9lZmlsaW5nLmVuZXJneXNhZmV0eS5jYS5nb3YvZUZpbGluZy9HZXRmaWxlLmFzcHg_ZmlsZWlkPTUyNzc1JnNoYXJlYWJsZT10cnVl&ntb=1

[13] https://www.bing.com/ck/a?!&&p=b7363f8e06ea3c2cJmltdHM9MTcxNTgxNzYwMCZpZ3VpZD0wYjRmMDQ3Ny0wYmJiLTY2MzAtMjY4Yy0xNmI5MGE0MDY3Y2UmaW5zaWQ9NTIwNg&ptn=3&ver=2&hsh=3&fclid=0b4f0477-0bbb-6630-268c-16b90a4067ce&psq=Fast+Trip+Settings%3a+California+IOU+Comparison&u=a1aHR0cHM6Ly9lZmlsaW5nLmVuZXJneXNhZmV0eS5jYS5nb3YvZUZpbGluZy9HZXRmaWxlLmFzcHg_ZmlsZWlkPTUyNzc0JnNoYXJlYWJsZT10cnVl&ntb=1

Figure 4. Fast Trip Fire Mode Illustrative Example Reliability Impacts Scenario 1



As Scenario #1, consider the situation where the circuit is in seasonal Fire Mode. In this scenario, Fuse 7 would open to clear the fault. The resulting outage would be limited to the ten customers and troubleshooting would be a simple matter of patrolling the short amount of overhead line downstream from the fuse. As Scenario #2, consider the situation where FTFM is enabled on the substation breaker CB. For the same fault located downstream from Fuse 7, CB would open and Fuse 7 may not open. The resulting outage would impact 1,000 customers instead of ten customers. Outage duration would be longer because troubleshooting would be much more extensive. Line personnel would patrol the entire mainline and possibly all fused laterals using step restoration until the problem was found. One way to mitigate the reliability impacts of the coordination issues associated with FTFM is to replace the lateral fuses with TripSavers, discussed later in this report.

No relay upgrades were needed to implement FTFM in Tier 3, where FTFM was implemented through setting changes for the Glenbrook, Kingsbury, Roundhill, Canyon, Kyle Canyon, and Mt. Charleston circuits. However, new relays were needed for the Incline 4100, 4200, and 4300 circuit breakers, along with telecommunications upgrades to remotely enable SCADA[14] functionality. All work completed for this substation and technical operations work were not charged to the NDPP regulatory asset, but rather those costs were recovered in a general rate case.

FTFM capability was installed on the four remaining Tier 3 circuits located in northern Nevada. TripSavers were installed on the Tier 3 Curry Street, Downs, and Heybourne circuits. The Steamboat 213 R5 recloser required setting changes only to protect Virginia City Highlands Tier 3. This work was not charged to NDPP. Implementation in Tiers 2 and 1E requires adding 77 additional circuits to the FTFM program, achieved by enabling the capability on a combination of substation circuit breakers and line reclosers.

[14] System Control and Data Acquisition.

As discussed previously, the Companies assessed approximately 160 substation circuit breakers and line reclosers to identify the devices that will require FTFM, evaluated the capabilities of the existing equipment, and documented required improvements. For the circuit breakers that were identified as requiring FTFM, the existing equipment falls into three categories:

1. Fully capable of FTFM and requires no upgrades required = 31 breakers
2. Not capable of FTFM, but capable of HLT which require minor relay upgrades = 29 breakers
3. No capability and requires major replacement of existing relays = 17 breakers

Substation engineering and telecommunications engineering assessed telecommunications upgrades required for remote SCADA control. The capital improvement cost estimates total $10.7 Million, representing $9.6 Million for relay upgrades and $1.1 Million for telecommunications improvements. The estimates are contained in Appendix D Tier 3, 2, 1E Relay Capabilities spreadsheet. A small amount of OMAG in 2025-2026 was also estimated, totaling about $70,000 for telecommunications work. The Companies plan to recover the costs for this work in a future general rate case.

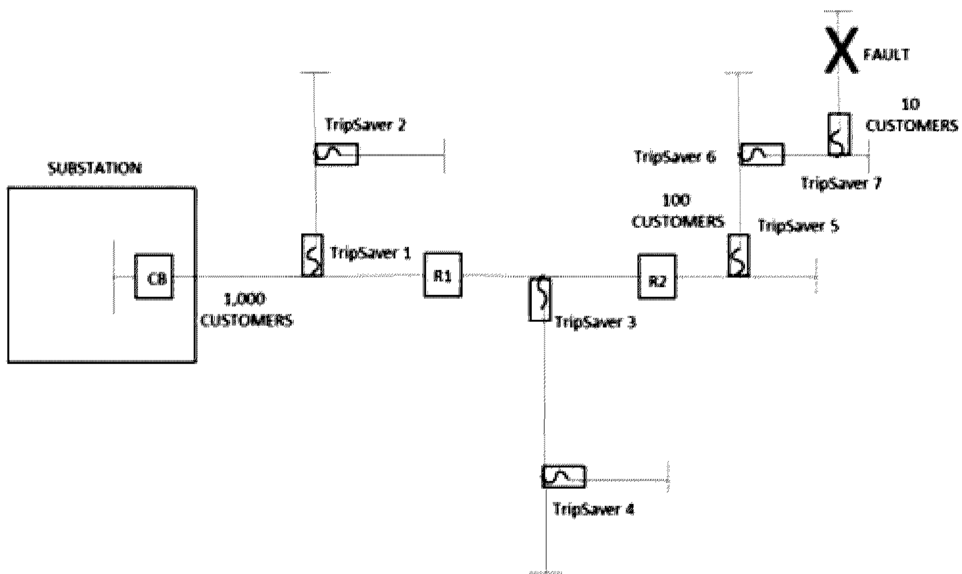
Implementation requires substantial engineering and field personnel to design, procure, and install the equipment. Using both internal and external resources, completion will take approximately three years, based on lead times for purchasing equipment being currently at two years. It is anticipated this work will commence 2026 and will complete FTFM implementation for Tier 3, 2, and 1E by Q4 2026. For the line reclosers, 75 devices were assessed, and 54 were determined to be FTFM capable. For the remaining 21 reclosers identified for replacement, five of the 21 reclosers are single phase reclosers. The estimated capital cost to upgrade the line reclosers is $1.05 Million, based on an estimate of $50,000 per recloser. The Northeast regional engineer is evaluating replacement options for single phase reclosers.

System protection engineering issued settings for 31 circuit breakers with existing FTFM capability. Regional engineers are issuing settings for 54 line reclosers with existing FTFM capability. The settings will be implemented by the system protection operations department with completion by year's end 2024. The estimated $300,000 to implement is planned to be recovered in a future general rate case.

TripSavers

To further reduce clearing times and minimize the outage impacts of FTFM during the Tier 3 implementation, the Companies used the fast trip capabilities of TripSavers. TripSavers have an Auto/Manual lever that allows them to be switched between normal ("Automatic or Auto") and alternate ("Manual") settings. In 2023, the Tier3 TripSavers were reconfigured to consider FTFM so the Manual setting included instantaneous tripping with no time delay. In this mode, TripSavers typically coordinate with upstream breakers and line reclosers that have FTFM enabled. In the shown in Figure 5, the fuses from Figure 5 have been replaced with TripSavers, shown as TripSaver 1 - TripSaver 7.

Figure 5. TripSavers for Fault Clearing



As Scenario #3, consider the situation where the system is in Fire Mode. In this scenario, TripSaver 7 would open to clear the indicated fault. Like Scenario #1, the resulting outage would be limited to ten customers and troubleshooting would patrol the short amount of overhead line downstream from TripSaver 7. As Scenario #4, consider when FTFM is enabled on substation CB and the TripSavers also have FTFM enabled.[15]

Instead of the breaker opening like Scenario #2, TripSavers 5, 6, and 7 would open. The resulting outage would be limited to 100 customers instead of the 1,000 customers in Scenario #2. Troubleshooting would also be reduced compared to Scenario #2. Line personnel would patrol the lateral downstream from TripSaver 5 and can quickly ascertain that the problem was downstream from TripSaver 7. While the primary function of the TripSavers has been to eliminate expulsion fuses, they can provide a secondary benefit by helping to reduce potential outage impacts associated with FTFM.

The 2024-2026 NDPP calls for approximately 1,200 TripSavers in Tier 2 and 1E at a capital cost of $12.8 Million. The Companies' 10-year plan calls for an additional 1,400 TripSavers to be installed in Tier 2 and 1E during 2027-2029 at a capital cost of $16.5 Million. The TripSavers planned and approved for installation by 2026 year-end, plus acceleration of mainline-only TripSavers aligns with FTFM implementation goals for Tiers 3, 2, and 1E in 2026.

Alternatives Considered to FTFM Implementation

Delaying implementation of FTFM in the areas forecasted as highest risk would deny those areas the safety benefit from the added layer of resilience on high-risk days during fire season, based on an industry-adopted enhancement to PSOM. FTFM's near-instantaneous trip decreases the potential of an equipment caused ignition that may otherwise occur with normal, longer trip settings.

[15] Operating handle in Manual/alternate, instantaneous settings enabled.

The Companies considered performing no capital improvement work for substation circuit breakers and line reclosers and only implementing FTFM on the devices that have existing capabilities. The associated risk is that only 56% of Tier 3, 2, and 1E would be fast trip enabled, which is less than 5% of the total overhead system.

The Companies also considered not accelerating of the existing TripSaver deployment plan for Tier 2 and 1E to avoid any acceleration of expulsion fuse replacement beyond the 2024-2026 NDPP. This has undesirable reliability consequences when FTFM is deployed on circuits without TripSavers. Accelerating the installation of even a select group of TripSaver and provides additional risk reduction benefits from removing more expulsion fuses from heightened risk areas as well as the reliability benefits discussed above.

3.3 Emergency De-Energization Wildfire Policy

The Companies are adopting an Emergency De-Energization Wildfire Policy ("Protection Policy") as part of their 2024 Enhanced Fire Season Protocols. An emergency de-energization wildfire condition occurs when an uncontrolled and unpredictable wildfire is at risk of encroaching established safety boundaries from electric utility facilities thereby increasing the risk of additional ignitions if the fire makes contacts with energized facilities. Safety distances are predefined, and encroachment occurs when an uncontrolled wildfire comes within the established safety distances of electric facilities. The Emergency De-Energization Wildfire Policy is an escalated response to address severe wildfire conditions when an active wildfire threatens to encroach the predefined boundary around electric infrastructure.

Because wildfires can rapidly spread based on different variables, the safety distances are predefined and encroachment risk is based on data-driven wildfire spread pattern projections.

Multiple situational awareness technologies (wildfire cameras, and satellite hot spot detection, etc.), fire agency information, and weather condition data are monitored to support early credible wildfire detection. The Companies' equipment shall be de-energized as quickly as is feasible when the Companies' assets are within the encroachment boundary of a wildfire.

System operators will use credible sources for wildfire information to obtain information needed to determine a fire's proximity to electric infrastructure and how fast the fire is developing and traveling. Credible sources include 911, Transmission & Distribution ("T&D") field operations, Emergency Management, Fire Mitigation Officer, Grid Operations, Reliability Coordinator, and Customer Operations. The wind speed information at the fire location or nearest weather station will be obtained using **nvenergy.westernweathergroup.com** before de-energization to determine which wildfire encroachment boundary applies. However, when weather data is not available or in doubt, the Fire Mitigation Officer will utilize all available sources of information to decide where the wildfire fits within Table 1.

Facilities will be de-energized in the event of a verified wildfire encroachment. A wildfire encroachment will occur if there is credible information that a wildfire has breached the minimum safety distance in the table below.

Table 1. Identified Wildfire Risk Level and Safety Buffer Distances

Severe Fire Danger Rating (SFDI)	Sustained Wind Speed (mph) < 15 Distance (miles)	15 to 30 Distance (miles)	> 30 Distance (miles)
Low	[redacted]		
Moderate (non-Fire Tier)			
Moderate (Fire Tier areas)			

The distances in Table 1 exclude time for Grid Operations to assess the data and study the potential impacts before de-energizing. The Companies anticipate approximately fifteen minutes and up to one hour to perform those actions and then begin de-energization via the nearest [redacted] to the target area.

If transmission facilities are located within the de-energization zone, the Real Time Contingency Analysis tool will be used to study system impacts and plan for required mitigation. If generation facilities are located within the de-energization zone, the Balancing Authority Operator will study the impact and plan for required mitigation.

Localized de-energization will be implemented without prior approval. Localized de-energization events are described as individual distribution circuits up to a full substation including associated transmission lines. The Companies' on-duty system operator will notify leadership if any de-energization may result in larger impacts. Broader impacts include de-energizing multiple substations or a generation facility, cascading transmission contingencies, and/or declaring an Energy Emergency Alert level.

For elevated impacts and depending on the specific circumstance of an event, the Companies may elect to keep a facility(ies) in service despite a wildfire encroachment. These instances are at the discretion of the Companies' President & CEO or a delegate, authorized in writing, acting on behalf of the Companies' President and CEO. Examples include keeping a powerline energized for public safety or system stability.

The system operator is expected to ***de-energize*** as quickly as feasible all electrical T&D facilities and supporting assets within the wildfire encroachment safety boundaries outlined in Table 1 using the closest [redacted] A power line within the encroachment safety boundary should be de-energized immediately upon notification that an active wildfire has encroached the established safety boundary.

An illustrative example is shown in Figure 6. In some cases, opening the [redacted] at the transmission substation is required to complete immediate de-energization, even though more customers may be impacted. Once NV Energy personnel visually verify acceptable field conditions, the system operator is authorized to begin restoration. De-energized facilities that are not required to be de-energized under the emergency de-energization parameters may be restored immediately.

Figure 6. Wildfire Emergency De-Energization SCADA Protocol

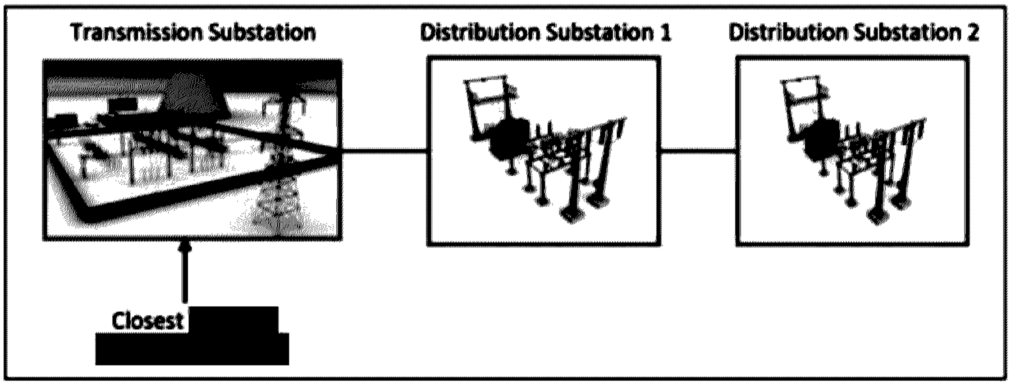
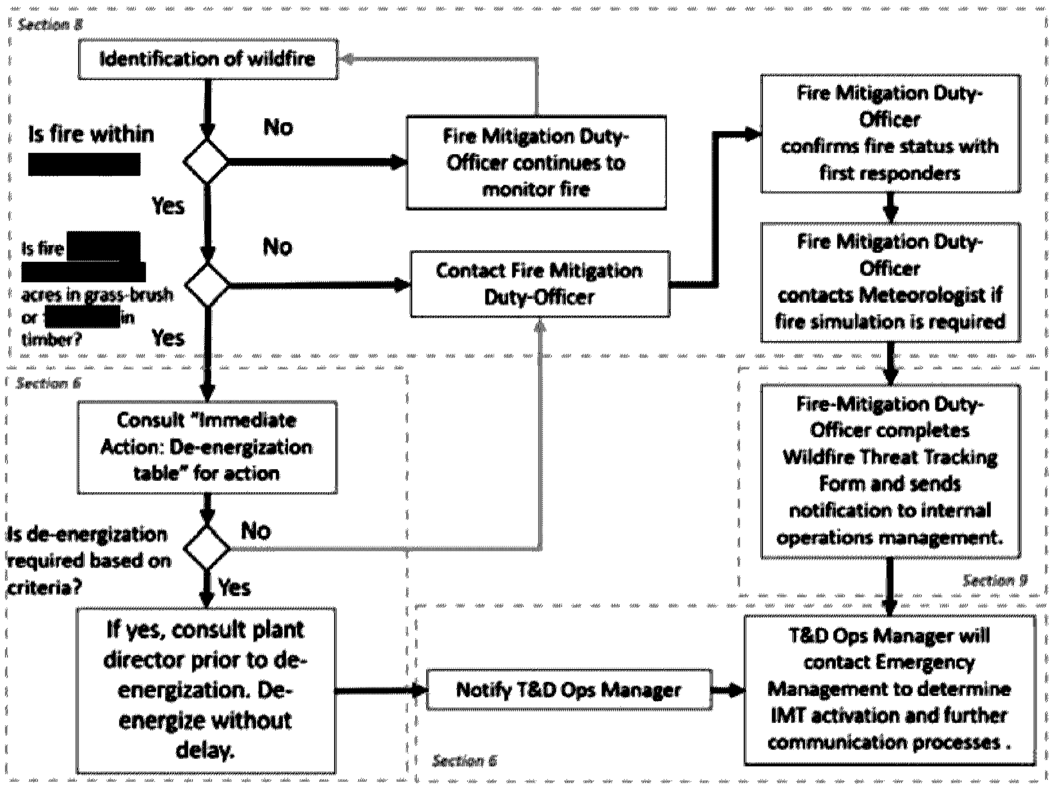


Figure 7. Flowchart for Emergency De-Energization Assessment



The Companies continue to evaluate emergency de-energization wildfire protocols, in line with other utilities and industry practices, and may modify the Emergency De-Energization Wildfire Policy based on additional information, or their experience gained.

4 Conclusion

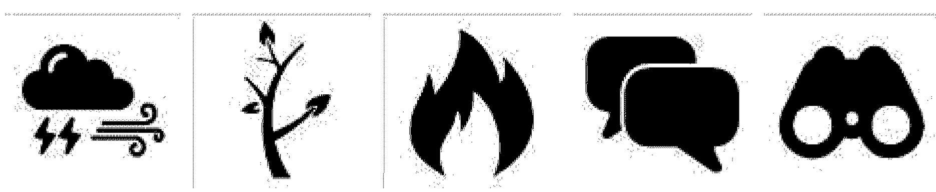
The Companies' risk-based approach to natural disaster mitigation underpins these important changes for the 2024 wildfire season. The Companies facilitated an expert working group session with statewide external stakeholders to outline these enhanced fire season protocols and solicit input from the fire protection districts, and emergency management offices in jurisdictions impacted by these provisions, including the state divisions of forestry, lands, parks, and emergency management. The Companies continue to collaborate with critical stakeholders to coordinate emergency response to natural disasters and mitigation efforts to proactively reduce potential of increasing threats. Proactive communication and trainings were developed and delivered to Company employees managing these protocols. Customer communication plans are enhanced to address scenarios presented by these enhanced protocols. The Companies present this informational update after carefully considering the alternatives discussed here. The devastating wildfires and extreme climate conditions that have occurred in recent years warrant expanding PSOM when wildfire threat conditions reach an intolerable threshold in all of NV Energy's service territories as an immediate and proven public safety option. Wildfires are not relegated to the existing Risk Tiers and an added layer of safety protocols for all of the Companies' overhead systems is in the public interest. The expanded PSOM plans will follow the established criteria and processes that currently exist for Tier 1E. NV Energy will expand FTFM, as an industry best practice, for Tier 2 and 1E, anticipating 75% completion of these areas during 2024 and 100% by Q4 2026. As experience is gained, evaluation of FTFM expansion will continue. The emergency de-energization due to wildfire encroachment is a critical aspect to public safety and having a structured approach will lend efficiency and harmonization with other NDPP practices. As noted above, the Companies anticipate including these mitigation measures in an application to amend the NDPP that will be filed in the coming months, but in the meantime these important safety protocols will be implemented for the 2024 fire season.

As of this date, no costs for expansion of PSOM, implementation of FTFM or the consideration of the Emergency De-Energization Wildfire Policy have been included in the NDPP regulatory asset account.

APPENDIX A: NV ENERGY'S 2024 PUBLIC SAFETY OUTAGE MANAGEMENT (PSOM) PLAN

This section contains updates to the Companies' PSOM Plan to be implemented for the 2024 Fire Season.

PUBLIC SAFETY OUTAGE MANAGEMENT



Public Safety Outage Management ("PSOM") Plan

Date: May 2024

Contents

- **PURPOSE:**

NV Energy is committed to public safety and the risk of wildfires is a top priority. Public Safety Outage Management ("PSOM") is a proactive de-energization program that the Companies use to help protect communities from the risk of wildfires. During a PSOM, NV Energy ("NVE" or "Company") may shut off power when certain fire weather conditions exist to help prevent equipment or debris from starting or contributing to a wildfire. This document contains the **minimum** guidelines for proactive de-energization of facilities when the when the risk of keeping the system energized is greater than impact of de-energizing the grid.

Objective:
Communicate the criteria, processes, and methods NV Energy uses for PSOM. Coordinate the response and restoration of a PSOM to reduce any risk of energized facilities being involved in a public safety incident under extreme weather conditions.

Scope:
This plan is used by NVE Incident Management Teams ("IMT")[16] and NV Energy leadership for implementing PSOM. This plan is effective for all areas determined to be in wildfire season by the NVE Meteorology Team.

- **FIRE SEASON PREPARATION**

Incident Management Team
NV Energy uses an Incident Command System ("ICS"),[17] a standardized approach for responding to incidents, established by Federal Emergency Management Agency ("FEMA"). This affords the ability to use a scalable hierarchical approach and common terminology for PSOM that is also used by public safety partners. PSOM events are managed and coordinated through NVE's IMT. The IMT is also responsible for developing an Incident Action Plan ("IAP") document that lists objectives and resources necessary to implement PSOM events.

Preparing for Fire Season Mode
Every year, prior to Fire Season, circuits at risk will be identified for special seasonal operational settings. Identified circuits will be placed into Fire Season Mode,[18] which means there will be no automatic circuit reclosing, resulting in a single fault locking out the circuit. This reduces the likelihood that sparks could result from re-energizing the line prior an observation of field conditions. Certain circuits may also

[16] Per NV Energy Corporate Emergency Response Plan
[17] https://training.fema.gov/emi.aspx
[18] Details of Fire Season Mode are located in the Electric System Control Center NVE-DIS-005 Fire Season Operating Procedure.

be set to "Fast Trip Fire Mode", where trip sensitivity will be higher during certain wildfire risk conditions.

Communications Infrastructure Providers Informed of Proactive De-energization Zones

Annually and prior to Fire Season, telecommunication companies that could be impacted by PSOM will be provided with shapefile maps of each Proactive De-energization Zone (PDZ) by NV Energy's Major Accounts department, based on maps provided by NDPP's GIS team.

Entering Fire Season Mode

NV Energy monitors and identifies conditions to enter Fire Season. Factors considered include fuel moisture conditions, severe fire danger index, and the Energy Release Component percentile.[19]

Microgrid Deployment at Angel Peak

During a PSOM event that impacts the Angel Peak PDZ but not the Mt. Charleston PDZ there may be an opportunity to deploy a microgrid to keep the Kyle Canyon circuit energized. The microgrid is activated by powering the Kyle Canyon Substation using special-purpose generators. The microgrid operation requires coordination between NV Energy Lines Operations, Substations, System Control, and the generator company to set up and maintain the generators for the duration of an event. The Angel Peak PDZ microgrid can be activated prior to de-energization or after a PSOM.

[19] Per NV Energy's Wildfire Season Operations Plan

- **PSOM PROCEDURES**

PSOM procedures are implemented according to the level of risk that has been determined through advanced analytics and modeling. Unique criteria apply for Tier 3 "Extreme Risk", Tier 2 "Severe Risk", and for the balance of NV Energy's service territory that includes Tier 1 Elevated (1E) and Tier 1 Wildland Urban Interface (WUI). All areas with a Tier designation are identified as being at risk from wildfires. The distinct approaches are outlined in this section. A Composite Risk Index has been developed to codify wildfire risk based on a variety of factors.

Tier 3 Extreme Risk Procedures

This section outlines criteria and procedures for Extreme Risk Tier 3.

Tier 3 Thresholds

Table 1. Tier 3 De-Energization Thresholds[20]

Region	Burning Index ("BI")[21]	Wind Gust ("V_g")	Composite Risk Index ("CRI")[22] ($0.00256 \times V_g^2 \times BI$)
North PDZs (Greater Lake Tahoe)	> 70	> 40 mph (60 mph max)[23]	> 287
South PDZs (Angel Peak and Mount Charleston)	> 70	> 45 mph (60 mph max)[24]	> 363

[20] Thresholds and guidelines were determined by analysis from fire risk models. The results of these models are included with the Natural Disaster Protection Plan filings and are refreshed periodically.

[21] Burning Index ("BI"): A value that is determined from the moisture content of a forest, wind speed, and other factors that affect burning conditions and from which ease of ignition and behavior of a forest fire may be estimated.

[22] Composite Risk Index ("CRI"): The CRI is wind gust force (in units of psf) multiplied by the BI, which is expressed mathematically as ($0.00256 \times V_g^2 \times BI$).

[23] PSOM criteria, wind gusts greater than 60 mph with Red Flag Warning issued by National Weather Service.

[24] PSOM criteria, wind gusts greater than 60 mph with Red Flag Warning issued by National Weather Service.

Figure 1. Northern Nevada Tier 3 PSOM Thresholds

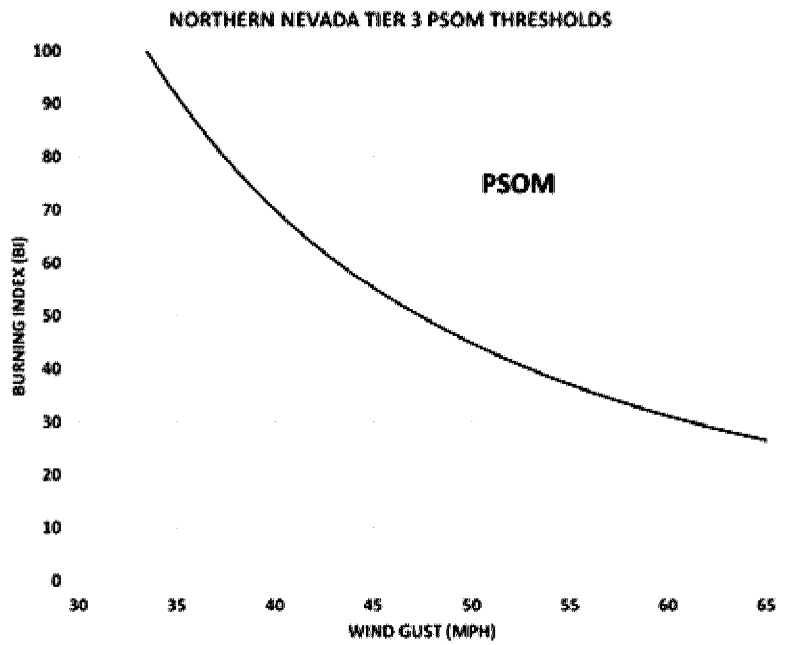
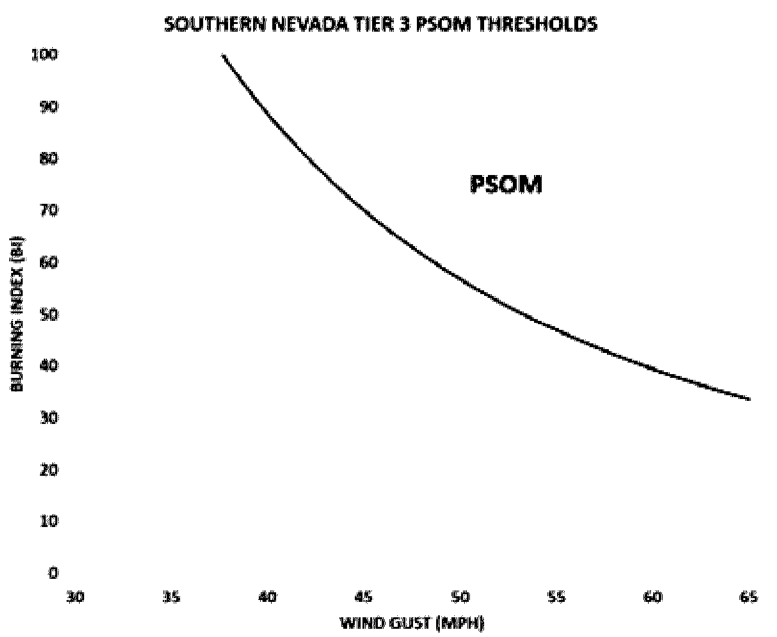


Figure 2. Southern Nevada Tier 3 PSOM Thresholds



Tier 3 Mitigation Measures
This section describes mitigation measures that are taken in accordance with the CRI.

Table 2. Hierarchy of Mitigation Measures Considered for the Deployment Based on CRI De-Energization Threshold

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
90% and/or National Weather Service issues Fire Watch	Conduct patrols and perform corrections
95% and/or National Weather Service issues Red Flag Warning	Conduct patrols and perform corrections and pre-stage fire resources
Exceed Composite Risk Index	Proactive de-energization

Tier 2 Severe Risk Procedures
This section outlines criteria and procedures for Severe Risk Tier 2.

Tier 2 Thresholds
Tier 2 has prescriptive thresholds but considers a wide variety of factors such as:

- Weather Conditions;
  - National Weather Service Red Flag Warnings;
  - Available non-Company weather data from existing Remote Automated Weather Stations ("RAWS");
- Field observations and vegetation conditions;
- Information from first responders and key stakeholders; and
- Wildfire activity and location of any existing fires affecting state resource availability.

Table 3. Tier 2 De-Energization Guidelines

Risk Tier	BI	Wind Gust (mph)	CRI
Tier 2	> 70	> 60 mph	> 645

Tier 2 Mitigation Measures

Table 4. Hierarchy of Mitigation Measures Considered for Deployment Based on CRI De-Energization Threshold

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
95% and/or National Weather Service issues Red Flag Warning	Conduct patrols and perform corrections and pre-stage fire resources
Exceed Composite Risk Index	Proactive de-energization

Balance of Service Territory Procedures

This section outlines criteria and procedures for the balance of NV Energy's service territory, including Tier 1E, Tier 1, and the WUI.

Balance of Service Territory Thresholds

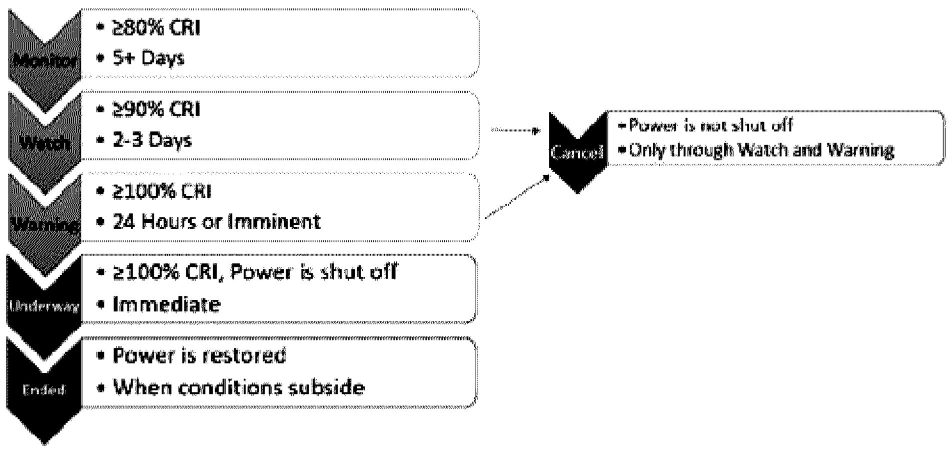
No prescriptive thresholds but considers a wide variety of factors such as:

- Weather Conditions;
  - National Weather Service Red Flag Warnings;
  - Available non-Company weather data from existing Remote Automated Weather Stations ("RAWS");
- Field observations and vegetation conditions;
- Information from first responders and key stakeholders; and
- Wildfire activity and location of any existing fires affecting state resource availability.

Table 5. Balance of Service Territory De-Energization Guidelines

Risk Tier	BI	Wind Gust (mph)	CRI
Balance of Territory including Tier 1E, Tier 1, WUI, and all areas	> 70	> 70 mph	> 878

Figure 3. PSOM Stages



Monitor This level is for informal notification only. At approximately 5 days if the CRI is 80% or above, enter this level, and begin preliminary communications within the company and notifications of external first responders, other utility companies, public safety partners, and telecommunication companies.
- If at 2 to 3 days the CRI is below 90%, remain at this level.

Watch At 2 to 3 days if the CRI is above 90%, enter this level, and begin external notifications of our customers and other stakeholders which is reflected in our media plan
- If within 24 hours of de-energization the CRI is less than 100%, remain at this level

Warning At 24 hours if the CRI is above 100%, enter the warning level and begin external notifications of our customers and other stakeholders which is reflected as directed by the Public Information Officer

Canceled Should conditions subside, a PSOM may be canceled by NV Energy's Incident Commander at any time prior to de-energization

Underway Immediate if the CRI is above 100%, upon direction of the Incident Commander, begin de-energization of at-risk circuits

Ended When the CRI is below 80%, re-energize circuits as safe conditions are met

Balance of Service Territory Mitigation Measures

Table 6. Hierarchy of Mitigation Measures Considered for the Deployment Based on CRI De-Energization Threshold

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
95% and/or National Weather Service issues Red Flag Warning	Conduct patrols and perform corrections and pre-stage fire resources
Exceed Composite Risk Index	Proactive de-energization

- **DEFINITIONS**

- ***Burning Index ("BI")***
- The BI is a value determined from the moisture content of a vegetative fuels, wind speed, and other factors that affect burning conditions and the contribution of fire behavior to the effort of containing a fire. The BI "difficulty of controlling the fire" is derived from a combination of Spread Component - how rapidly a fire will spread - and the Energy Release Component - how much energy will be produced.

Composite Risk Index ("CRI")
The CRI is wind gust force (in units of psf) multiplied by the BI, which is expressed mathematically as $(0.00256 \times V_g^2 \times \mathrm{BI})$[25]

- **PSOM STAGES**

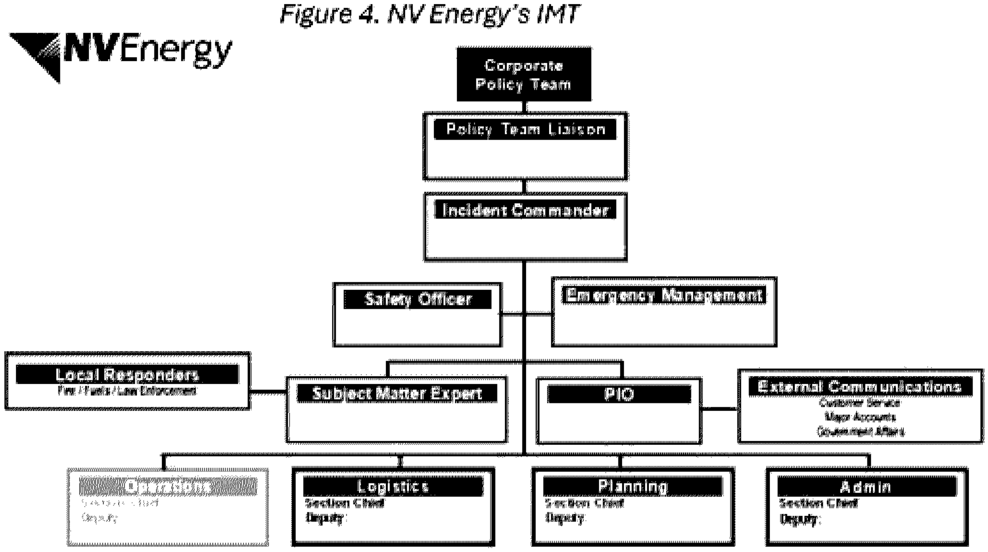
This section describes the PSOM Stages.

[25] CRI weather forecasting is located at https://nvfireweather.com/forecast/

- **PSOM INCIDENT MANAGEMENT TEAM**

NV Energy uses FEMA's ICS for a structured approach to PSOM. This provides a common approach and hierarchical structure to complete required actions. NV Energy's IMT structure is included in the following Figure 4. The IMT is expanded and contracted as conditions warrant. The IMT fits within NV Energy's overall leadership for seamless coordination within the organization. This is effectuated by establishing a Crisis Management Team ("CMT") that represents the core functions of the IMT. The Incident Commander ("IC"), Emergency Management Officer, Public Information Officer ("PIO"), and Fire Mitigation / Subject Matter Experts collaborate with company executives represented in the Policy Team and Policy Liaison Team.

Figure 4. NV Energy's IMT



- **PSOM STAGES DETAILED ACTION STEPS**

This section provides detailed information about monitoring, notifications, and activation timeline beginning up to 5 days from event. Because fire weather conditions may materialize quickly best approximations are used. Tier 3 criteria are more rigid.

Table 7. CRI to Gauge Action Steps

Risk Tier	BI	Wind Gust (mph)	CRI
Tier 3: North PDZs (Greater Lake Tahoe)	> 70	> 40 mph (60 mph max)	> 287
Tier 3: South PDZs (Angel Peak and Mount Charleston)	> 70	> 45 mph (60 mph max)	> 363
Tier 2	> 70	> 60 mph	> 645
Balance of Territory including Tier 1E, Tier 1, WUI, and all areas	> 70	> 70 mph	> 878

Conditions = Monitor (~3-5 Days out)

Enter **Monitor** if CRI reaches or exceeds 80%
The monitor stage is used when conditions are approaching levels that could reach CRI levels.

Actions to Take Under Monitor Conditions

- Informal notification and schedule daily meetings with IMT
  - IMT considers resource availability (communications, contract fire resources, crews, etc.)
    - IC requests the Planning Section Chief to implement daily weather conditions monitoring
    - Provide daily weather reports to IMT and consider notification to the Emergency Response Organization ("ERO")[26] via email and/or Teams
    - Informal notifications to public safety partners and NV Energy service providers

Conditions = Watch (~2-3 days out)

Enter **Watch** if CRI reaches or exceeds 90%
The Watch stage begins formal engagement of the IMT at a scaled-back level.
Consider mitigation efforts including patrols, corrections, and fire resources
Formulate an IAP

[26] The ERO consists of a broader group of NV Energy personnel beyond those identified for the IMT.

Actions to Take Under Watch Conditions

- Notification and daily meetings scheduled with IMT
    - IMT develops an IAP and considers resource availability (communications, contract fire resources, crews, etc.)
        - IC requests the Planning Section Chief to implement daily weather conditions monitoring
        - Provide daily weather reports to IMT and ERO via email/Teams
        - Section Chiefs begin building and communicating with their Sections as needed for a possible PSOM

    - IMT Goals/ Tasks
        - Set schedule for ERO Calls
        - Update NV Energy's Policy Team
        - Begin Mutual Assistance coordination, as necessary
            - Crisis Management Team ("CMT")
                - Notify external stakeholders about a possible PSOM
                    - PIO – Follow communications procedures for PSOM
                        - Increase resources to notify customers at the 72- and 48-hour mark
                        - Customer Care will make calls to critical facilities, medium sized customers, and Green Cross Customers
                        - Provide notification to Communication Infrastructure Providers ("CIP")
                    - Fire Liaison – Verify availability of fire resources and begin handing out radios and weather stations to field crews
                    - Emergency Management – As needed, a liaison will be established with Liberty, Plumas Sierra, and TDPUD[27] and Appendix C Utility Communication Plan will be followed.
                        - Communicate with local emergency managers (emails, phone calls, texts, and/or WebEOC)
            - Planning – Continue IAP, situation updates, and meeting schedule
            - Admin – Continue administrative as directed by the IC
            - Logistics – Schedule generators, Cellular on Wheels ("COW") and Customer Resource Center ("CRC") deployment

[27] See Appendix E Inter-agency coordination

- Operations – Prepare for generator deployment, as necessary
  - Review NV Energy Playbooks and switching orders

Conditions = Warning (~24 hours or less)

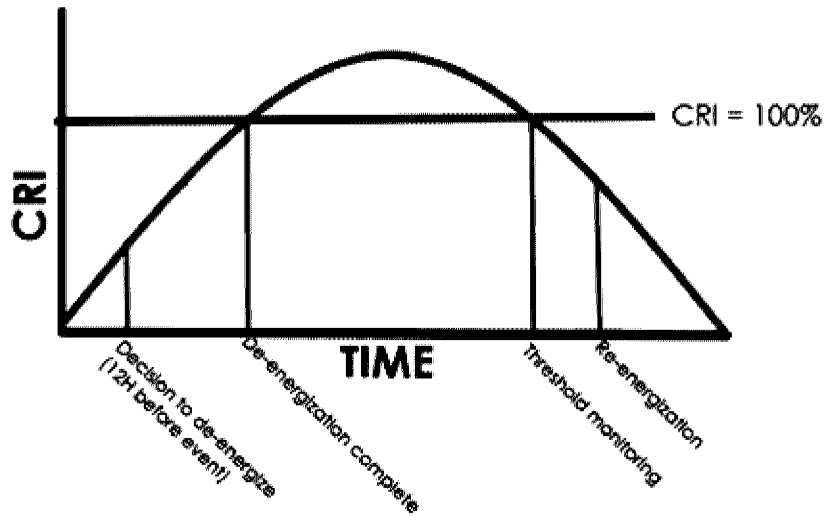
Enter **Warning** if CRI reaches or exceeds 100%
Prepare for de-energization in Tier 3 PDZs
Continue analysis for de-energization in all other areas
Implement mitigation efforts including patrols, corrections, fire resources, Customer Resources Centers, and emergency responders

Actions to Take Under Warning Conditions

- Notify Policy Team
- Activate full IMT and fill staff as necessary
- Open the EOC
- Notify external stakeholder and customers
- CMT
  - PIO – Follow media plan for PSOM event
  - Schedule ERO calls – set cadence for calls
  - Provide daily weather reports to IMT and ERO via email/Teams
  - Section Chiefs begin building and communicating with their Sections as needed for a possible PSOM

- IMT Goals/ Tasks
  - Determine time of exceedance (CRI)
  - Decision to de-energize should be established within 12 hours of the threshold exceedance – considerations include wind speeds (forecasted and actual), fuel moistures, relative humidity, time to de-energize, and resources
  - Event summary with backup information will be given to the Policy Team Liaison to share with the Policy Team, this summary will include analytics from risk modeling, NVE meteorologist, and PSOM Scorecard
  - Continue threshold monitoring
  - Determine time of re-energization and communicate
  - Based on circuits/PDZ(s) actual conditions and meeting thresholds, determine areas requiring full patrolling and communicate to Operations
    - CMT continue tasks
    - Planning -IAP completed and shared
      - Creation and completion of the PSOM scorecard for each affected transmission line and PDZ(s)
    - Admin – Continue tasks
    - Logistics Continue tasks

Figure 4. Decision and Monitoring Timeline for a PSOM Event Within 24 Hours Using CRI



Conditions = PSOM Underway

After time to de-energize is established:

1. Share PDZ(s) affected and timeframes with IMT to be shared with their personnel.
2. IMT will be advised of the de-energization and communications and updates will be distributed as outlined in the communication procedure.
3. IC will request a confirmation of orders from the following groups over the Command radio channel which is outlined in the IAP.
   a. Operations Section Chief
      i. System Control Lead
      ii. Lines Department Lead(s)
   b. Fire Mitigation Liaison

Actions to take PSOM Underway

- IMT Goals/ Tasks
  - Determine time of exceedance (CRI)
  - Decision to de-energize should be established within 12 hours of the threshold exceedance
  - Notify external stakeholders about the event
    - PIO – Follow communications procedures for PSOM event
      - Notify customers at the 24- and 12-hour mark

        - Customer Care will make calls to critical facilities, medium sized customers, and Green Cross Customers
        - Provide notification to CIP
  - Event summary with backup information will be given to the Policy Team Liaison to share with the Policy Team, this summary will include fire risk analytics from and the NVE Meteorologist, and the PSOM Scorecard(s)[28]
  - Continue threshold monitoring

  - Determine time of re-energization and communicate
  - Based on circuits/PDZ(s) actual conditions and meeting thresholds, determine areas requiring full patrolling and communicate to Operations.
    - Crisis Management Team – Continue tasks
    - Planning – IAP completed and shared
      - Creation and completion of the PSOM scorecard for each affected transmission line and/or PDZ(s) as determined by the IC
    - Admin – Continue tasks
    - Logistics – Continue tasks
    - Operations – Plan for de-energization
      - Share IAP with crews
      - Review playbooks
      - Stage resources
      - Verify switching orders

RE-ENERGIZATION PLAN

After CRI is below threshold

- IC will put an announcement over the Command radio channel authorizing start of re-energization process. IC will request a confirmation of orders from the following groups:
- Fire Mitigation Liaison
- IMT will be advised of the de-energization; communications and updates will be distributed as outlined in the communication timeline
- Status of the line restoration will be input by the Operations Section, but it will be tracked and shared by the Planning Section in the Situation Report
- Situation Report tracking form will be updated every 30min - 1hr
- Operations Section Chief will announce over the Command radio channel informing that the circuits in impacted PDZ have all been re-energized and all customers should be back in power
- IMT will be advised of the re-energization and communications and updates will be distributed as outlines in the communication timeline/ media plan

[28] The Event Evaluation Scorecard is Appendix C.

Patrolling – Restoration –
Actions to Take

- IMT Goals/ Tasks
    - The CRC, Operations, and EOC will remain in constant contact during this time
    - The EOC will de-activate once all customers have been restored to power, crews are demobilized, and the CRC is shut down
        - Operations –
            - Conduct patrols on all Tier 3 de-energized circuits meeting threshold
            - Consider patrols on all other circuits as necessary
            - Internal and external resources will check in and check out with the Incident Command Post ("ICP")[29]
            - Share status of PDZ restoration with EOC via Section Chief
            - Notify external stakeholders about the restoration
                - PIO – Follow communications procedures for PSOM event
                    - Increase needed resources to notify customers
                    - Provide notification to CIP

Conditions = PSOM Ended
Upon re-energization complete, enter PSOM Ended
Actions to take PSOM Ended

IMT Goals/ Tasks
PIO – Follow communications procedures for PSOM ended

Complete the following requirements within the required timeframes
PSOM Ended + 24 hours
Actions to Take

- Legal submits a copy of the final external stakeholder notification form to Public Utilities Commission of Nevada ("PUCN") which gets shared to internal and external stakeholders at the time of complete restoration of customers.

PSOM Ended + 14 days
Actions to Take

- Emergency Management completes After Action Report for the PSOM event

PSOM Ended + 30 days
Actions to Take

[29] Established by the IC.

- IC or designee will prepare a full report and submit to Legal to review and submit to PUCN.

- **DEMOBILIZATION**

When the event has slowed, more customers power has been restored, and the need for extensive coordination has decreased, the IC can scale the response to meet the needs of the event.

Demobilization of resources will be decided at the operational level. The Operations team will notify the Planning Section when any resource has been activated or de-activated, so it can be tracked on the ICS form and IAP.

All these efforts will be documented and tracked in the IAP completed by the Planning Section.

- **DOCUMENTATION**

Information to be documented and tracked for reporting and compliance purposes:

- Forecast information before and during the event
- Notes from meetings that determined if it was a go/no-go
- The notification that was provided to telecommunication and Green Cross customers
- Number of customers involved
- Time for re-energization – any issues that occurred (if we have any information on any debris in the lines that will be helpful)
- Information on CRCS – how many people used them (if we have it)
- Information on the public safety/partner engagement
- What infrastructure we used/brought to the site – and cost (if that is available)
- Our overall budget/cost for the PSOM
- Lessons learned or issues we encountered

- **CONTACTS**

Verizon Crisis Response Team
1(800) 981-9558 24/7 Line

Verizon Area Manager
1(415) 385-6015 mobile
1(925) 279-6119 office

AT&T/First Net Emergency Number - 1(800) 574-7000

NV Energy FirstNet Specialist Local Contact 1(858) 200-5496

- **REVISIONS**

Rev	Date	Description of Changes	Approved By
1	05/24/2024	Clarification on wildfire season needed to implement PSOM plan. Communication to CIP from Emergency Management personnel. Communications plan update.	Alex Hoon

- **APPENDIX A: Incident Command Post ("ICP") and Staging Area Locations**

Preparedness Planning Meeting Areas will be opened approximately 24 hours prior to an event. These are subject to change

- Pre-Planning Meeting area (24 hours before event and can accommodate 50-70 people)
  - Incline Fire Protection District (FPD) Fuels Building - 71 Carry Way Mound House, NV 89706
  - Carson office for smaller events
  - Ohm for Reno area
  - Elko Office for Elko
  - Winnemucca Office for Winnemucca

Staging Area Locations:

- Incline Village
  - Diamond Peak Ski – CRC and ICP
- Tahoe Douglas
  - Whittel High Schol (The Old School)– CRC, Staging Area, ICP
  - Pending: Carson Fuji Park – CRC, Staging Area, ICP
- Mt Charleston
  - Staging Area - Spring Mountain Visitor Center
  - ICP – The Retreat at Mt Charleston

- **APPENDIX B: PSOM Event Notification Form**

NVEnergy	NV Energy Public Safety Outage Management (PSOM) Notification Form		
Report Date		Report Time	
Report Number	**PSOM- YYYY - N/S - Event # - Report #**		

Notification Type			
De-Energization Potential		De-Energization Initiated	
Initiated Assessment to Re-Energize (Patrols)		All Lines Re-Energized	
		De-Energization Event Canceled	

Is this an update notification?	Yes		No		Initial	
If "yes", provide an update number:						

Maps of impacted areas:	https://www.nvenergy.com/safety/psom

Potential Impact

County	Zone	# Of Customers/ GCC	Estimated De-energization Time	Actual Time of De-energization	Estimated Time of Re-energization
Total Number of Customers:					
Number of Green Cross Customers (GCC):					

List of Impacted Critical Infrastructure: (including, but not limited to, hospitals, fire stations, police stations, water treatment facilities, schools, communications facilities etc.)		
Zone	**Description of Infrastructure**	**Estimated Time of Restoration**

Public/ Customer Notification Information and Report

Method of Public Notification (Check All That Apply)		
Recipient/ Type of Notification or Update		**Est. Completion of notification (Time)**
Local Stakeholders/ First Responders		
Telecommunications Providers		
Major Accounts		
Public Information Officers (PIO)		
Green Cross Customers		
Customers (Text, Call, and/ or Email)		
Social Media/ Media Outreach		
Website Updated		

Disclaimer

This document and the data included herein are intended for the sole use of the intended recipient(s). The above data is based on an assessment in wildfire risk tiers in NV Energy's service territory. NV Energy is not responsible for any missing data. Supporting data is collected by NV Energy personnel and its agents using several different data sources. Notwithstanding that, NV Energy makes no representations or warranties, express or implied, of the accuracy or completeness of the information herein. NV Energy is not liable for any use or reliance upon any of the information.

- **APPENDIX C: PSOM Qualification Criteria - Event Evaluation Scorecard**

County	Location	Circuit	# of Customers	Estimated De-energization Time	Estimated Time of Re-energization
Total Number of Customers:					
Number of Green Cross Customers:					
Projected End Date of Event:					

Based on the forecasted conditions for the above circuit(s), a qualitative score for each individual parameter can be seen below.

The scores range from zero to ten with ten being highest confidence and zero being low confidence. A "go" or "no-go" can be given to an area where a number cannot be assigned

EXPLANATION:
"How confident are we that an ignition event will not be caused by our infrastructure"
10 – High confidence our infrastructure will fare well without de-energization
0 – Our infrastructure is not ready and could cause an ignition event.

Go – Stakeholder is ready and prepared to go through a PSOM event
No-Go – Stakeholder is not ready or prepared - ****Must provide reasoning behind this***

	Score
1. **Vegetation Management**: Based on the last **tree** vegetation management cycle completed Responsible owner: Operations (Vegetation Management) Received input from:	0-10
2. **Patrol/Detailed Inspection:** Based on the last patrol or inspection completed Responsible owner: Operations (Lines) Received input from:	0-10
3. **Local Fire District Input and Fire Resources**: Available fire resources in the area and response capability, give detailed response if needed. Responsible owner: Fire Management Received input from:	0-10

Received input from:	
11. Customer Resource Centers: Readiness levels for the customer resource centers Responsible owner: Admin (Community Relations) Received input from:	GO or NO-GO
12. Restoration Readiness – Distribution: Based on the restoration readiness for the affected circuits Responsible owner: Operations (Lines, Substations and System Control) Received input from:	0-10
13. Restoration Readiness – Transmission: Based on the restoration readiness for the affected circuits Responsible owner: Operations (Lines, Substations and System Control) Received input from:	0-10
14. Local Emergency Management Input: Their assessment of field conditions and necessity for a PSOM event Responsible owner: Emergency Management Received input from:	GO or NO-GO
15. Customer/ Public Communications: Resource/ timeline readiness to get information out to customers Responsible owner: PIO (Corporate Communication) Received input from:	GO or NO-GO
16. OTHER: Include any other topics or concerns to be considered for the event – *there will be no score associated with this section. (Example: Air Quality Index, Extreme heat, Extreme cold or other weather conditions)* Responsible owner: All Section Chiefs	N/A
Total	

4. Fuels Mitigation Work: Assessment of field conditions near impacted infrastructure, last time **ground fuels** management was completed Responsible owner: Fuels/ Fire Management Received input from: Did a FBAN develop possible fire behavior information: Yes / No	
5. Large Event/Visitor Status: If a significant event is projected during the potential PSOM event duration Responsible owner: PIO (Major Accounts) Received input from:	GO or NO-GO
6. Utility Infrastructure Readiness: Any critical water or sewage treatment facilities will have any issues Responsible owner: PIO (Major Accounts) Received input from:	GO or NO-GO
7. Communication Infrastructure Provider Readiness: to include "any company that provides Broadband Internet Access Service (BIAS), Personal Communications Service ("PCS"), local exchange service, or Voice over Internet Protocol service, or is a Telephone Company. Responsible owner: PIO (Major Accounts) Received input from:	GO or NO-GO
8. Radio Communications: Any radio communication concerns regarding the 800mHz radio system Responsible owner: Logistics (Telecommunications) Received input from:	GO or NO-GO
9. Infrastructure Design – Distribution: Input based on the base design of overhead infrastructure and its expected resiliency Responsible owner: Planning (Distribution Design) Received input from:	0-10
10. Infrastructure Design – Transmission: Input based on the base design of overhead infrastructure and its expected resiliency Responsible owner: Planning (Distribution Design)	0-10

Initiate a PSOM event if the total score of the above qualitative assessment includes any of the following:

- Lower than 40 out of 80 (maximum), **or**
- Three or more individual category scores are lower than three (0, 1, or 2) **or**
- One or more of the category scores is extreme or unacceptable.

The final decision to initiate a PSOM event would be made by either the IC or Policy Team Liaison for the event. If there are any "go or no-go" scores, they will need to be considered on a case-by-case basis.

Recommendation to Initiate PSOM Event: YES / NO

Score Card completed on:	
Reasoning behind recommendation:	
Summary of any changes from previous score card:	
Brief summary of additional mitigation efforts being implemented for the event:	

Recommendation/ Additional Mitigation Approved by:

____

Incident Commander

____

Policy Team Liaison

- **APPENDIX C: Utility to Utility Communication Plan**

Purpose: To outline a communication and coordination timeline between NVE, RC West Truckee Donner Public Utility (TDPUD), Plumas Sierra Utility, and Liberty during a possible PSOM event that would impact TDPUD and Liberty's electric distribution grid.

Impacted Lines by Utilities

TDPUD – North Truckee 101 Transmission line (Verdi PDZ), Summit Metering Stations 102 Transmission line (Verdi PDZ), and Truckee Summit Metering Station 607 Transmission
Liberty - North Truckee 101 Transmission line (Verdi PDZ), Summit Metering Stations 102 Transmission line (Verdi PDZ), Truckee Summit Metering Station 607 Transmission, Buckeye-Meyers 111, Incline Village PDZ, Stateline PDZ, California 204, Muller 1296, and Topaz 1261, 112 Buckeye to Roundhill, Kingsbury 2800 (Heavenly PDZ)
Plumas Sierra – 619 Transmission Line
RC West – All transmission outages

Notification Timeline

- 4-6 Days out from event:
  - An email notification with an external stakeholder form from NV Energy will be sent to TDPUD/ Liberty/ Plumas Sierra contacts.
  - RC West will be communicated with through Electricity Subsector Coordinating Council (ESCC) via established protocols.

- 2-3 Days out from event:
  - An email notification with an external stakeholder form from NV Energy will be sent to TDPUD/ Liberty/ Plumas Sierra contacts.
    Note: Information will be added to the email about additional communication to be held within 48 hours of the event.
  - TDPUD/ Liberty/ Plumas Sierra representative is invited to NV Energy's ERO calls or called to be told about the incoming weather.
  - *Note: TDPUD/ Liberty will ensure the other is informed and will be available and on the update call.*

- 0-2 Days out from event:
  - A daily call from an NV Energy Point of Contact (POC) to TDPUD/ Liberty/ Plumas Sierra contacts to discuss the event and give the below information (as available).
    - Agenda
      - Estimated de-energized time and duration
      - Probability
      - Impacted area or lines
        - See above listed possible impacted lines for each utility

- TDPUD/ Liberty/ Plumas Sierra to identify a single POC for NVE to communicate directly with through the remaining steps of the event.

Note: Set standard time for daily update calls
Note: Cannot have call between 1600-1700 due to Liberty restrictions

- De-energization – at time of actual de-energization
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established

- Weather decreased notification
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established
    - NVE will let TDPUD/ Liberty/ Plumas Sierra know that the weather decreased around the transmission line and NVE is preparing to patrol

- Patrols
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established to let them know NVE has begun patrols of the transmission line

- Ready to re-energize
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established to let them know NVE has finished patrols and are ready to re-energize the transmission line.

- **Appendix D: PSOM Communications Plan**

PSOM AWARENESS

Prior to wildfire season:

- Confirm existing PSOM zones and customer lists for each zone/subzone
- Confirm Green Cross list for each zone (Customer Operations)
- Update website and customer lists to reflect any new PSOM zones or changes to zones
- Send letters to impacted customers to alert them they are in a PSOM zone and why we PSOM
  - Include name of PSOM Zone
  - Invite to relevant open house event (in person or virtual)
- Send press release to alert media to the "start" of PSOM season, and explain why we PSOM
- Activate PSOM paid media plan – radio, social, out of home elements
- NDPP Update to Stakeholders (March)

PSOM CUSTOMER OUTREACH OVERVIEW

PSOM Monitoring (3-5 Days Prior)

- Send informal notification to Incident Command Team PIO group (corporate communications, customer service, major accounts, government affairs, community relations)
  - Potential Impacted Zones
  - Timing of potential event
- Confirm PSOM zone customer list readiness
- Customer Operations to pull list of potential Green Cross customer impacts – NV Energy tries to give at least 72 hours notification of a PSOM event, when possible
- Telecom and Emergency Management (Informal from Major Accounts and EM)

PSOM WATCH is issued – 2-3 Days Prior to Potential Event

- Create incident talking points, to be approved by Incident Commander:
  - PSOM notification level
  - Description of conditions
  - Timing of potential event (giving a start and stop range of 4-hours)
  - Impacted zone(s) and number of customers
  - CRC details, if available

- PIO Posts talking points in Incident Command Team ("ICT") Teams Channel for PSOM event
- Share talking points with ICT PIO group (corporate communications, customer service, major accounts, government affairs, community relations, regulatory affairs)
- Update customer phone, email, and text templates for PSOM WATCH
  - Send to customer notification team (Customer Programs & Services - Director and Senior Customer Self Service Analyst)
  - Review and approve drafts, confirm distribution
- Notify Impacted customers via phone, text, and email
- Update PSOM event information on www.nvenergy.com/psom
- Draft and send PSOM WATCH press release to appropriate media
- Notify area PIOs, if needed
- Post PSOM WATCH on social media channels

PSOM WATCH Continues - 2 Days Prior

- Update talking points, if needed, to reflect changes to impacted zones or other information
- Post talking points in ICT Teams Channel for PSOM event
- Share talking points with ICT PIO group (corporate communications, customer service, major accounts, government affairs, community relations, regulatory affairs)
- For zones still impacted, update notifications as needed, to share ongoing PSOM WATCH.
  - Send to customer notification team (Woody and Jorge)
  - Review and approve drafts, confirm distribution
- For zones no longer impacted, create separate call, email, and text notifications to communicate PSOM WATCH is canceled for these zones.
  - Send to customer notification team (Woody and Jorge)
  - Review and approve drafts, confirm distribution
- Update PSOM event information on www.nvenergy.com/psom
- Draft and send PSOM WATCH press release to appropriate media
- Alert PIOs of impacted areas, Governor's PIO
- Post PSOM WATCH on social media channels
- Consider updating paid radio and out of home in impacted PSOM areas to communicate PSOM WATCH

PSOM WARNING – 1 Day Prior

- Update talking points to reflect PSOM WARNING and any change to impacted zones and customer count, timing, or other significant information. Finalize and include CRC information
- Post talking points in ICT Teams Channel for PSOM event
- Share talking points with ICT PIO group (corporate comm, customer service, major accounts, government affairs, community relations, regulatory affairs)
- For zones still impacted, update notifications as needed, to share PSOM WARNING
  - Send to customer notification team (Woody and Jorge)
  - Review and approve drafts, confirm distribution
- For zones no longer impacted, create separate call, email, and text notifications and follow process outlines above to communicate with the PSOM WATCH is canceled for these zones.
  - Send to customer notification team (Woody and Jorge)
  - Review and approve drafts, confirm distribution
- Update PSOM event information on www.nvenergy.com/psom
- Draft and send PSOM WARNING press release to appropriate media
- Alert PIOs of impacted areas, Governor's PIO
- Post PSOM WARNING on social media channels
- Consider updating paid radio and out of home in impacted PSOM areas to communicate PSOM WARNING

PSOM UNDERWAY

- Update talking points to reflect PSOM UNDERWAY
  - Impacted zones and customer count
  - Event Start Time and Planned End Time (range of 4 hours)
- Post talking points in ICT Teams Channel for PSOM event
- Share talking points with ICT PIO group (corporate comm, customer service, major accounts, government affairs, community relations, regulatory affairs)
- For zones still impacted, update call, text, and email notifications regarding PSOM UNDERWAY
- For zones no longer impacted, create separate call, email, and text notifications and follow process outlines above to communicate with the PSOM WARNING is canceled for these zones
- Update PSOM event information on www.nvenergy.com/psom
- Draft and send PSOM WARNING press release to appropriate media
- Alert PIOs of impacted areas, Governor's PIO

- Post PSOM UNDERWAY on social media channels

PSOM ENDED

- Update talking points to reflect PSOM ENDED
  - Impacted zones and customer count
  - Event Start Time and End Time
- Post talking points in ICT Teams Channel for PSOM event
- Share talking points with ICT PIO group (corporate comm, customer service, major accounts, government affairs, community relations, regulatory affairs)
- Draft call, email, and text notifications for PSOM ENDED
  - Send to customer notification team under PIO
  - Review and approve drafts, confirm distribution
- Update PSOM event information on www.nvenergy.com/psom
- Draft and send PSOM WARNING press release to appropriate media
- Alert PIOs of impacted areas, Governor's PIO
- Post PSOM UNDERWAY on social media channels
- Resume general paid PSOM awareness campaign

- **APPENDIX E: Table of Abbreviations**

BHE	Berkshire Hathaway Energy
BI	Burning Index
BIAS	Broadband Internet Access Service
COW	Communications on Wheels
CRC	Customer Resource Center
CRI	Composite Risk Index
EOC	Emergency Operations Center
ERO	Emergency Response Organization
ESCC	Electricity Subsector Coordinating Council
FBAN	Fire Behavior Analyst
FPD	Fire Protection District
IAP	Incident Action Plan
IC	Incident Commander
ICS	Incident Command System
IMT	Incident Management Team
NDP	Natural Disaster Protection
NDPP	Natural Disaster Protection Plan
NV	Nevada
NVE	NV Energy
PDZ	Proactive De-energization Zone
PIO	Public Information Officer
POC	Point of Contact
PSOM	Public Safety Outage Management
PUCN	Public Utilities Commission of Nevada
RAWS	Remote Access Weather Station
TDPUD	Truckee Donner Public Utility District
WRMAG	Western Region Mutual Assistance Group

APPENDIX B: UTILITY BENCHMARKING OF FAST TRIP SCHEMES AND RELAY TECHNOLOGIES FOR FIRE MITIGATION

The following reports were filed with the California Public Utilities Commission and are included in this Appendix for reference:

1) Utility Benchmarking of Fast Trip Schemes and Relay Technologies for Fire Mitigation

2) Fast Trip Settings: California IOU Comparison

Natural Disaster Protection Plan Progress Report

Utility Benchmarking of Fast Trip Schemes and Relay Technologies for Fire Mitigation

Paper Authors and Contributors: [redacted], [redacted], [redacted]

Summary

PG&E developed Enhanced Powerline Safety Settings (EPSS) to help reduce wildfire risk by adjusting the sensitivity and speed of protective devices such as circuit breaker relays and reclosers. As currently implemented, circuits enabled with EPSS are configured to clear bolted fault conditions at 100ms.

PG&E's Distribution Asset Planning Department requested Applied Technology Services (ATS) to contact other utilities and discuss their philosophies for reducing wildfire ignitions using protective device setting changes similar to PG&E's EPSS initiative.

The purpose of these discussions is to provide insight into what types of protective device setting changes other west coast utilities, with similar wildfire risks to PG&E, are implementing to mitigate the risk of wildfire ignitions from utility equipment. Previous discussions were limited to other large California utilities such as SCE and SDG&E. These discussions expanded to include several other utilities in Washington State, Oregon and British Columbia.

These discussions indicate that many other utilities have implemented fast trip settings for several years. SDG&E has had some form of fast trip settings for about 10 years, SCE started implementing their fast trip schemes in 2018, and Avista has had fast trip settings for several years. PacifiCorp performed there first systemwide implementation in 2021. BC Hydro has only performed testing and a limited pilot on one distribution circuit.

Other utilities are also looking at new technologies to detect high impedance faults, detecting falling or broken conductors and sensitive ground settings. SDG&E has implemented Sensitive Ground Fault (SGF) and High Impedance Fault detection settings on their system. Most other of these are in the testing or pilot phase in evaluating these new technologies.

Table 1: Utility Comparison: Service Area, Voltages, and configuration

	PG&E	SCE	SDG&E	PacifiCorp (for CA)	Avista	BC Hydro
Location	Northern & Central California	Southern & Central California	Southern California	Northern California, Oregon, Washington	Eastern Washington, N. Idaho	BC Canada
Customers	5,200,000	5,000,000	1,400,000	47,000	400,000	1,800,000
Service Area (sq. mi)	70,000	50,000	4,100	11,000	30.000	340,000
Total Dist. Subs	651	900	134	47	131	260
Total Dist. Circuits	3.074	4.600	1.035	NA	350	1.670
Total Dist Circuit-Miles	108,000	69,800	17,085	3000	19.100	34,333
UG Circuit-Miles	27,000	31,000	10,558	600	Mostly OH	Mostly OH
OH Circuit-Miles	81,000	38,800	6,527	2400	Mostly OH	Mostly OH
Circuits in HFTD	800	1,074	70	21	154	NA
Voltages (kV)	21, 12, 17, 4	33, 16, 12, 4	12, 4	4.2-20.8	13.2, 24, 34	12, 25
Config./Grounding	3-wire uni-ground, 4-wire multi-ground	3-wire uni-ground, 4-wire multi-ground	3-wire uni-ground, 3-wire multi-ground via line-installed ground banks, 4-wire multi-ground	3 wire delta, 3 wire uni-ground, 4 wire wye	4-wire multi-ground	4-wire multi-ground

Table 2: Utility Comparison: Fast Trip Settings Comparison

	PG&E	SCE	SDG&E	PacifiCorp (for CA)	Avista	BC Hydro
Fast Trip	Yes	Yes	Yes	Yes	Yes	Testing & Pilot
Fast Trip Designation	Enhanced Powerline Safety Settings (EPSS)	Fast Curve (FC) Settings	Sensitive Relay Profile (SRP)	Sophisticated Program Control Settings (SPCS)	Dry Land Mode (DLM)	NA
Year in Service	2021	2018	~2010	2021	2021	NA
Operating Mode(s)	1	1	4	2	3	1
Settings Applied:	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific
Schedule	Daily (was seasonal in 2021)	Daily and Seasonal	Daily	Daily	Daily	Season
Fuse Over-reach (upstream 3-ph ganged trip operation for back feed prevention)	Yes	Typically No (potential use in limited cases)	Yes	Unsure	Yes	None
Activation Methods	Manual & Remote	Mostly Remote	Mostly Remote	Mostly Manual	Mostly Remote	Manual
Trigger	Weather Conditions, circuit and fire risk designation	Weather and Fuel Conditions	Extreme Fire Potential Index (FPI) or PSPS Forecasted	Weather Conditions	Fire Risk Potential Score (Risk =Prob. x Impact)	Weather Conditions

Internal

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	PG&E	SCE	SDG&E	PacifiCorp (for CA)	Avista	BC Hydro
Settings Description	Set phase and ground instantaneous pickups to see EOL for fused taps within the device protective zone (DPZ).Set definite time with delay not to exceed 0.1 seconds and use 0.02-second margin for coordinating between devices.	Used multiples of normal minimum trip to set fast curve settings with a time delay of typically 2 cycles. These settings typically help coordinate with other line protection devices, including fuses, while balancing ignition risk. SCE currently is using more sensitive multiple of pickup settings with a time delay of 4 cycles at a circuit-specific level. All reclosing is blocked while fast curve settings are enabled	Phase elements are set to trip at a minimum of 50% above peak historical load. Ground elements are based on peak historical trends and set utilizing a specific table contained within the settings methodology. Set definite time with 0.5-cycle delay. Multiple devices set with SRP may operate for downstream faults due to sensitivity and reduced protection margins.	The settings profiles include (but are not limited to): Normal (fuse saving application): Instantaneous trip followed by reclosing attempts with time-overcurrent trips. Elevated risk, no line reclosers, fuses on the line: Substation breaker will have an instantaneous trip followed by single reclose attempt after sufficient time to limit the persistence of fire. Elevated risk, line reclosers: Substation breaker will have instantaneous trip with no reclose attempt. Extreme risk, no line reclosers, fuses on line: Substation breaker will have instantaneous trip with no reclose attempt. Safety hold: for line worker usage during line operations where no reclosing occurs.	The settings profiles include: -Underreach 50: Stops short of downstream OLM recloser. No Dly -Overreach 50: Reaches to end of fused taps of rly zone. Bkr Coordinated Dly -51: fuse coordinated -Per/phase Inrush Blk -Base Dry Land Mode: Trip on 50 element, single reclose, trip on 51 (50s disabled) - Reduces fire risk by fast trip of temp faults. Perm faults fuse coordinate (Base OLM used for lower fire risk) -Fire 2-Shot: Trip on 50, reclose, trip on 50 (F2S for elev fire risk) -Fire 1-Shot: Trip on 50 with no reclosing (F1S for high fire risk)	Fast Trip tested in one area using Siemens Fuse Savers (FS). Similar to Hot Line tag settings, used for worker safety: 50ms Phase, 500 ms Ground (less false trips, better coord.). Also implemented single shot lockout

Table 3: Utility Comparison: Other Technologies being evaluated or in service

	PG&E	SCE	SDG&E	PacifiCorp (for CA)	Avista	BC Hydro
Sensitive Ground Fault (SGF) Detection Schemes	In service, thresholds set at 15 Amp, 15 sec	Generally, none; however, SCE has several dozen stations in service with impedance grounding to limit ground faults to less than 150 amps (low ground) or 50 amps (sensitive ground) where sensitive ground relay settings are applied	In service year-round. Set by evaluating peak neutral imbalance current on specific line section to set the SGF setting. SGF settings reviewed once per year for each device or when device operates in the field.	None	None	None
High Impedance Fault (HIF) or Down Conductor Detection (DCD) Schemes	Testing, Pilot	Pilot, in monitor/alarm mode only. Under specific circumstances, they apply these setting modes on line reclosers as part of their normal settings.	In service since 2011	Pilot, enabled in monitoring mode only	Plan to deploy to reclosers on trouble ckts meeting min load required by HIF algorithm	None
Falling Conductor & Open Phase Detection	AMI Voltage Detection	AMI Voltage Detection, piloting Open Phase Detection	AMI Voltage Detection, Pilot on several feeders with falling wires scheme (voltage synchrophasor based system)	None	None	None

Utility Discussion Summaries

San Diego Gas & Electric (SDG&E)

SDG&E operates an electric distribution system that serves approximately 3.6 million people through about 1.4 million meters. SDG&E's service territory spans more than 4,100 square miles from the California-Mexico border north to Southern Orange County and Riverside County and from the San Diego County Coastline east to Imperial County. SDG&E's system includes 134 distribution substations, 1,035 distribution circuits, 225,697 poles, 10,558 circuit miles of underground systems and 6,527 circuit miles of overhead systems. Approximately 3,500 circuit miles of overhead circuits are operated within the High Fire Threat District (HFTD). The electric distribution system consists of predominantly underground facilities (62%), but significant overhead facilities span the high-risk fire areas. The primary distribution voltage is mostly 12 kV, with some large areas of 4 kV. Grounding configurations for the distribution system include 3-wire uni-grounded, 3-wire multi-grounded via line-installed ground banks and a 4-wire multi-grounded configuration.

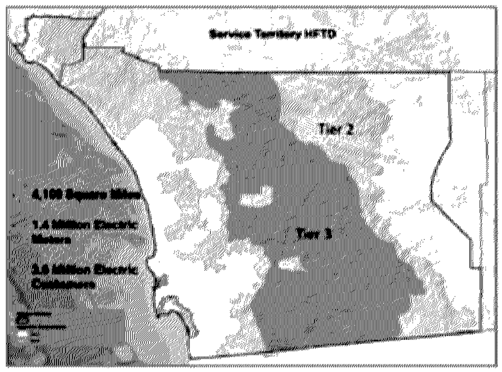

Figure 1: SDG&E Service Territory with HFTDs

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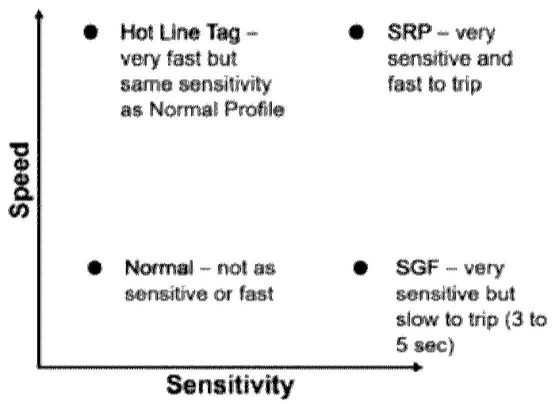
When extreme fire weather conditions or PSPS events are forecasted, SDG&E remotely enables Sensitive Relay Profile (SRP) on its system; SRP includes settings which make protective devices such as reclosers and circuit breakers more sensitive to faults on the overhead distribution system and activate quickly to interrupt power. SDG&E pre-identifies and maintains a list of these devices and can quickly communicate with its distribution operations control center to enable SRP when conditions warrant and in observance of wildfire safety efforts.

SRP settings include standard settings for all HFTD circuits:

- The phase minimum to trip set is at 50% above peak load on the circuit spanning a 5-year history
- The ground minimum to trip is based on peak historical trends and set using a specific table contained within the settings methodology.
- Definite time set with 0.5 cycle delay

The advantage of these settings is that there is a definite tripping time for all fault currents above minimum to trip. The disadvantage is that devices potentially do not coordinate, so downstream faults may lock out multiple devices. If multiple devices trip during an event when sensitive settings are enabled, SDG&E retains protection engineers and field resources available 24/7 to review event records to help determine if mis-coordination contributed to the event. These standby resources review each event in real-time and provide detailed information back to our operations teams and the EOC for situational awareness.



Normal Profile – Typical setting used to coordinate isolation of only faulted segments (Enabled when not in RFW or Extreme FPI)

SGF – Sensitive Ground Fault protection to detect high impedance faults (Always enabled)

SRP – Sensitive Relay Profile settings on phase and ground set to trip very fast to reduce fault energy (Enabled during PSPS or Extreme FPI)

Hot Line Tag – Enabled for crew safety when performing hot work. Same setpoints as Normal Profile, but very fast to trip.

Reclosing – Blocked year-round in HFTD

Figure 2: SDG&E Sensitive Settings Comparison

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Southern California Edison (SCE)

SCE operates an electric transmission/subtransmission/distribution system that serves approximately 15 million people through about 5 million customer accounts. SCE's service area spans about 50,000 square miles across central, coastal and Southern California, excluding the city of Los Angeles (served by LADWP) and other small cities served by municipal utilities. SCE's system includes about 900 distribution substations, 1.2 million distribution poles, 69,800 circuit miles of distribution primary lines, 31,000 circuit miles of distribution underground lines and 38,800 circuit miles of distribution overhead lines. The primary distribution voltage is predominantly 12 kV, with some large areas of 33kV, 16kV and 4 kV. Grounding configurations include both 3-wire uni-grounded and a 4-wire multi-grounded configuration. SCE mixes both 3-wire and 4-wire configurations on the same circuits.

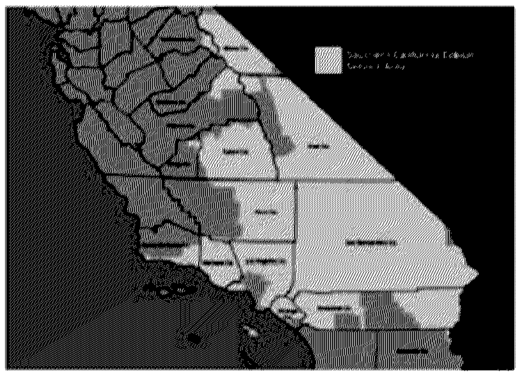

Figure 2: SCE Service Territory

In 2018, SCE initiated a program to deploy fast curve settings at substation circuit breaker relays and automatic reclosers and developed a plan for upgrading non-compatible and older vintage electromechanical and microprocessor relays for feeder circuits in high fire risk areas between 2020-2024.

SCE expects to complete upgrades to over 90% of all circuit breaker relays in high fire risk areas by 2022, with the remaining circuits upgraded by 2024.

SCE uses multiples of normal minimum trip to set fast curve settings with a time delay of typically two cycles. Normal minimum trip for each device is set to 150% of peak load. These settings typically help coordinate with other line protection devices, including fuses. SCE is presently evaluating its fast curve settings to increase sensitivity while maintaining reliability and coordination with fuses.

PacifiCorp

PacifiCorp serves more than 780,000 customers in 243 communities across Oregon, Washington, and Northern California. In California, PacifiCorp provides electricity to approximately 45,000 customers via 63 substations, 2,520 circuit miles of distribution lines, and 800 circuit miles of transmission lines. The service territory spans nearly 11,000 square miles, with just under half in HFTDs. Approximately 1,200 miles (36%) of all overhead lines are located within the HFTDs, with about 850 miles of overhead distribution lines (260 circuits) and 350 miles of transmission lines in HFTDs. PacifiCorp's distribution system is comprised of both single and three-phase in a range of system voltages between 4.2 kV and 20.8 kV circuits in 3 wire delta, 3 wire uni-ground, 4 wire wye configurations.

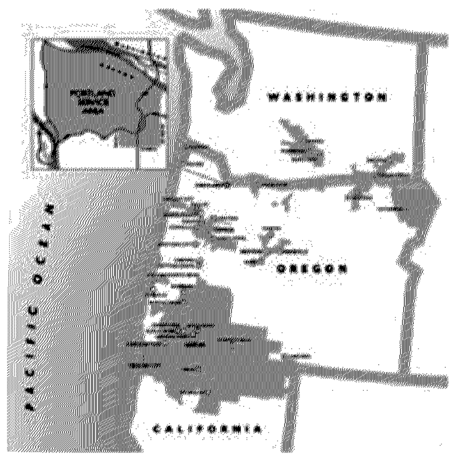

Figure 3. PacifiCorp Service Territory

Internal

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PacifiCorp conducted a pilot of Sophisticated Program Control Settings (SPCS) in 2021. This pilot evaluated the optimal approaches in using sensitive and sophisticated device settings to reduce wildfire risk and improve reliability. Devices, including relays, reclosers, and fuses, all have methods by which they are programmed to operate in response to a fault condition. If there is limited coordination between devices, it can increase the probability of equipment damage or delayed device operations, creating and extending an ignition risk. After experimenting and making minor modifications, PacifiCorp has adopted these settings as standard.

The settings profiles include (but are not limited to):

- Normal (fuse saving application): Instantaneous trip followed by reclosing attempts with time-overcurrent trips.
- Elevated risk, no line reclosers, fuses on the line: Substation breaker will have an instantaneous trip followed by single reclose attempt after sufficient time to limit the persistence of fire.
- Elevated risk, line reclosers: Substation breaker will have instantaneous trip with no reclose attempt.
- Extreme risk, no line reclosers, fuses on line: Substation breaker will have instantaneous trip with no reclose attempt.
- Safety hold: for line worker usage during line operations where no reclosing occurs.

These settings use definite time delays (12-cycles for substation breakers, 6-cycles between reclosers) to improve coordination. The settings also implement fuse overreach and harmonic blocking schemes. They are not currently enabling any sensitive ground fault detection.

Avista

Avista Utilities generates and transmits electricity and distributes natural gas to residential, commercial, and industrial customers. The service territory covers 30,000 square miles in eastern Washington, northern Idaho, and parts of southern and eastern Oregon. Avista provides electricity to 359,000 customers in two western states.

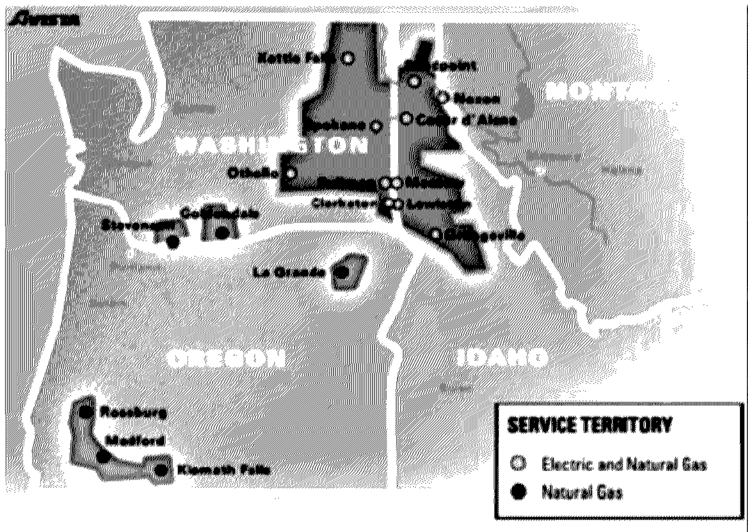

Figure 4: Avista Service Territory

Internal

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Avista experiences a fire season beginning around mid-July and lasting until late September or early October. During this season, Avista has historically disabled instantaneous overcurrent (50) tripping and reclosing on its distribution protection system, seeking to reduce spark ignition potential while maintaining coordination via time-overcurrent (51) elements.

As part of its ongoing effort to strengthen its wildfire resiliency program, Avista devised a new approach to its distribution operations during the fire season that seeks to calculate circuit-specific fire risks and allow operators to alter relay operating behaviors in response to the fire risk dynamically. The feeder relays and reclosers are programmed with three different "Dry Land Modes". Each mode further reduces electrical fault energy by reprioritizing instantaneous overcurrent (50) elements over time-overcurrent (51) elements. In addition, reclosing is reduced or disabled.

The settings profiles include:

- Underreaching 50 elements – Reach stops short of downstream Dry Land Mode (DLM) Recloser and trips without any delay
- Overreaching 50 elements – Reaches to end of fused laterals in relays protection zone (and overreaches downstream DLM Recloser, so has a breaker-coordinated definite-time delay of 6 cycles
- 51 elements – Set for fuse coordination
- Per/phase 2nd Harmonic Inrush Blocking – Per/phase inrush blocking allows for fast tripping on faulted phase when reclosing into a fault (for Fire 2-Shot mode, see below)
- Base Dry Land Mode: Fast Trip on instantaneous overcurrent followed by a single reclose attempt and switching to time-overcurrent elements. This behavior will quickly clear temporary faults, reducing fire risk, but maintain service reliability by coordinating with fuses for permanent faults. Base DLM is used when there is lower fire risk on a circuit
- Fire 2-Shot: Fast Trip on instantaneous overcurrent followed by a single reclose attempt after and trip again on instantaneous overcurrent elements. Fire 2-Shot is used when there is elevated fire risk on a circuit
- Fire 1-Shot: Fast Trip on instantaneous overcurrent with no reclosing. Fire 1-Shot is used when there is high fire risk on a circuit

Avista calculates a fire risk potential considering various weather, environmental, and operational data for the different distribution circuits. Based on real-time fire risk calculations.

The protective devices on a specific circuit can be moved into the appropriate "Dry Land Mode", allowing for a dynamic scheme that attempts to balance fire resiliency with service reliability.

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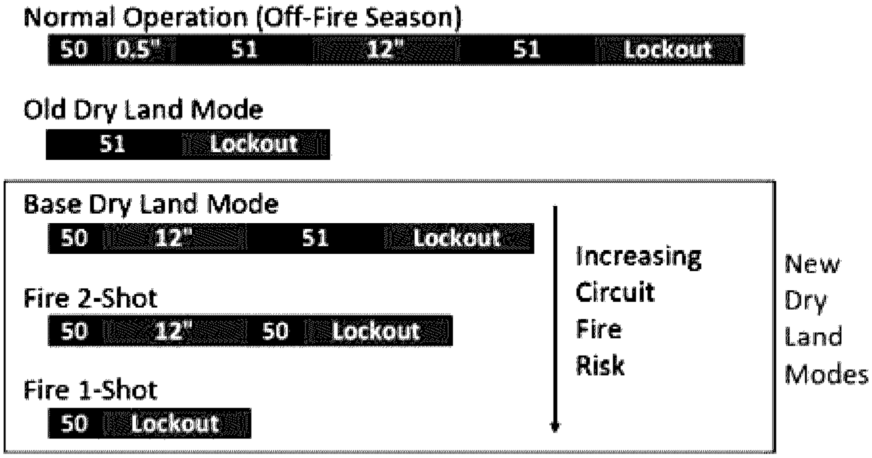

Figure 5: Avista's Fast Trip Approach (" indicates seconds)

Internal

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Fire Risk Potential

- Risk = Probability · Impact

- Probability Factors
  - Wind Gusts
  - Sustained Winds
  - Wind Direction
  - Relative Humidity
  - Fuel Type
  - USDM Drought Index
  - Fire Preparedness Levels
  - Feeder OMS Data
  - Feeder Health
- Impact Factors
  - Public Safety
  - Societal Costs
  - WUI Map
    - Infrastructure
    - Development
    - Fuel Type
    - Ignition Probability
    - Fire-Spread Risk
    - WUI Tier 0-3

- Fire Risk Score for each distribution circuit
  - 8-Day Forecast

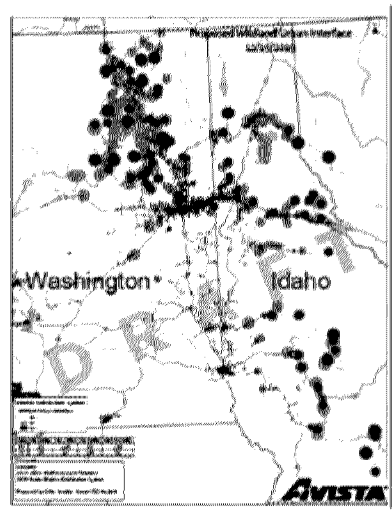


Figure 6 Avista's Fire Risk Potential Methodology

British Columbia Hydro (BC Hydro)

BC Hydro is a Crown corporation owned by the government and the people of British Columbia, Canada. They generate and deliver electricity to 95% of the population of BC. They serve over four million people. Electricity is delivered over 11,362 miles of transmission lines and 34,333 miles of distribution lines. The distribution system comprises 12.5 kV and 25 kV circuits and uses a 4-wire multi-ground configuration. Historically, BC Hydro experiences a fire season beginning around August and lasting until late September. However, the fire seasons have been starting earlier in recent years due to drier conditions.

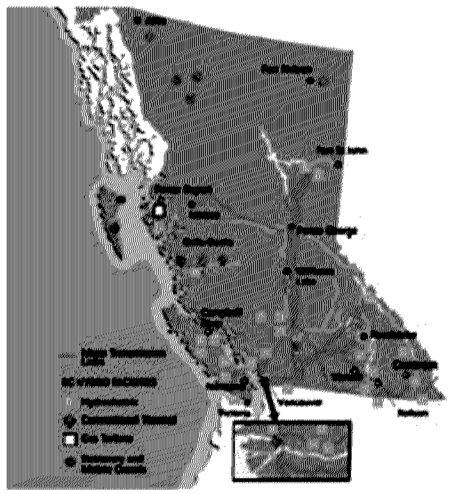


Figure 7 BC Hydro Service Territory

Internal

BC Hydro performed lab testing and conducted a field pilot of distribution circuit fast trip settings. Their implementation used Siemens Fuse Saver (FS) devices. FS devices are capable of very fast tripping (1/2 cycle or 0.01s). However, these devices have limited load current ratings and fault duty capability (100A and 4kA, respectively), restricting their use to taps and lateral sections of circuits. The FS are programmed with coordinated tripping, fast tripping mode, and single-shot reclosing lockout settings. BC Hydro envisions using circuit specific settings that provide some level of coordination between devices. The Fast Trip settings were tested at Powertech before the field pilot. They do not implement any sensitive ground fault settings or high-impedance (HIF) fault detection schemes.

The fast trip settings are similar to hot line tag settings used for worker safety: 50ms Phase-overcurrent and 500 ms Ground-overcurrent. The settings are tailored to minimize false trips and provide better coordination.

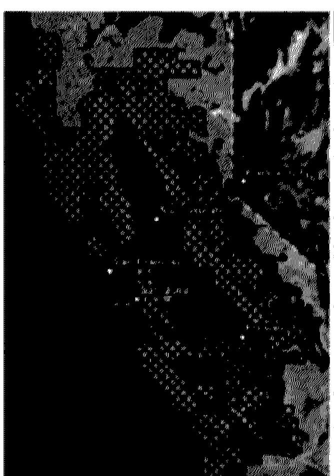
Fast Trip Settings: California IOU Comparison

"Fast Trip Setting" California IOU Comparison

June 2022

Together, Building a Better California

PG&E Service Territory Overview

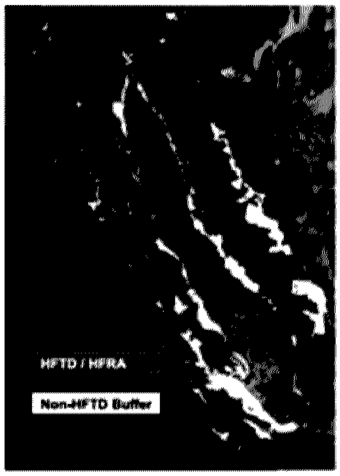


PG&E Service Territory

PG&E Service Territory Overview	
Service Area	~70K Square Miles
Customers	~5.4M Electric Utility Customers
Distribution Circuit Miles	~107K Line Miles
Transmission Circuit Miles	~18K Line Miles
Service Territory Description	There is high wildfire risk across many remote areas within PG&E's ~70,000 square mile service territory. California contains thousands of microclimates in which fire conditions differ based on location and topography.

Fast Trip Settings Program | 2

Fast Trip Program Summary



Fast Trip Program	
Program Name	**Enhanced Powerline Safety Settings**
First Deployed	2021
Current Scope	HFTD / HFRA / Select Non-HFTD Buffer
Devices Used	• Circuit Breakers • Line Reclosers • Fuse Savers
Protection Summary	• Circuit specific settings provide some level of coordination between devices • Phase and ground instantaneous pickups set to see end-of-line protection beyond non-ganged devices within the expanded device protective zone (DPZ) • 50P and 50N definite time set ≤ 0.1s with 0.02s coordination margin between devices • When possible, a low-set ground current pickup and definite time delay element is enabled for high-impedance fault (HIF) detection (sensitive-ground-fault/50GS)
Activation Criteria	EPSS activated if any of the following: • Fire Potential Index (FPI) >= R3 • Relative Humidity below 20% • Projected wind speeds 25+ mph • Dead Fuel Moisture below 9%

Fast Trip Settings Program | 3

Fast Trip Device Protection Overview

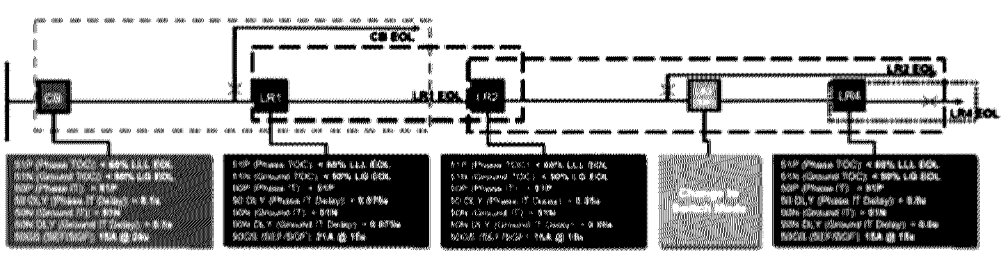
EPSS makes our system devices more responsive to wildfire risks by

Faster Fault Detection
Faster trip settings detect distribution primary faults more quickly to reduce incident fault energy

Reduce Fuse Single Phase Operation
Detect faults beyond fuses to clear across all threephases

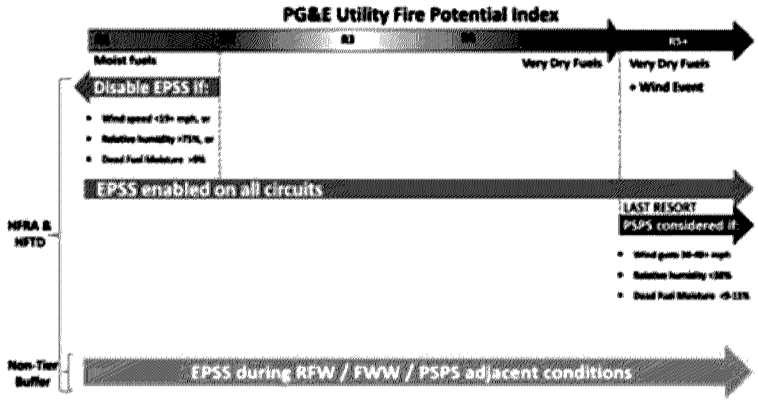
Higher Impedance Fault Detection

Fast Trip Device Protection
• EPSS Settings are stored in settings groups rather than with feature selection cut-in/cut-out. • Settings are placed back into "normal" groups during energization following patrolling to avoid inrush trips • Horstman Navigator LM Fault Indicators and Line Sensors can detect within the 0.1s programmed response time



Fast Trip Settings Program | 4 4

Fast Trip Enablement Event-Driven Criteria



NOTE: RFW = Red Flag Warning; FWW = Fire Weather Watch; PSPS = Public Safety Power Shutoff

Enablement criteria as of 06/13/2022

Fast Trip Settings Program | 5

Outage Response & Restoration

Outage Response & Restoration	
Outage Response Target	240 minutes
Dedicated Response Crews & Resources	• Dedicated crews for restoration and readiness response • Pre-position rapid response helicopters available to fly with 20 minutes notice • Leverage Fault indicators and refined patrol strategy to accelerate fault finding and restoration • Focus on having no unknown cause EPSS outages
Automatic Testing / Reclosing / Step Restoration	• Automatic testing is not performed and reclosing is disabled as part of the EPSS enablement instructions • Patrol is required and step restore is performed for outages on EPSS enabled circuits
Fault Indicators	Fault indicators provide visual or remote indication of faults on the system – PG&E plans to deploy these to quickly identify hazards and improve restoration times. **PG&E's 2022 Plan Includes:** • Install 1,600+ units on targeted locations by end of year • Prioritize EPSS HRFA / HFTD circuits with lowest reliability • Along circuits, install on fuse taps greater than 2 miles in length
Fuse Savers	A fuse saver provides faster response to faults than traditional fuses and can be SCADA enabled to operate in concert with EPSS protection schemes. **PG&E's 2022 Plan Includes:** • Install 136 units with 88 in current scope by end of Q2, and 48 emergent units by end of Q3 • Prioritize against EPSS HRFA / HFTD circuits with highest CEMI impact • Upgrade fuses with fuse savers at critical locations that will result in lower CEMI impact
Outage Customer Support & Communications	Proactive communication efforts will be targeted to ~1.8M potentially impacted customers across the 1,018 EPSS capable distribution circuits. **PG&E's 2022 Plan Includes:** • Advanced notification and regular updates for planned outages • Updates after and during unplanned EPSS outages

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SCE Fast Trip Setting Program

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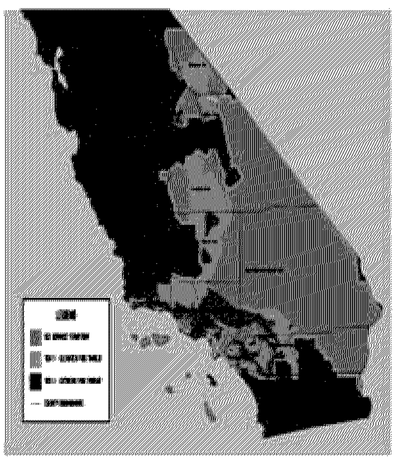
SCE Service Territory Overview



SCE Service Territory Overview	
Service Area	~50K Square Miles
Customers	~5M Electric Utility Customers
Distribution Circuit Miles	~69.8K Primary Overhead & Underground
Transmission Circuit Miles	~13.1K Overhead & Underground
Service Territory Description	About a quarter of SCE's service area across central, coastal and southern California is in high fire risk areas

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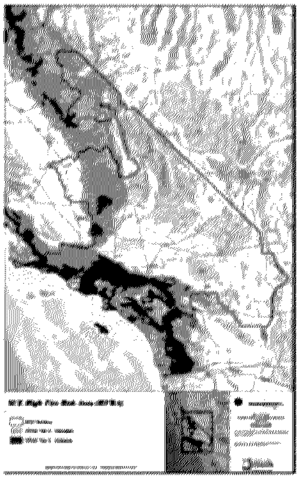
SCE's Fast Trip Program Summary



Fast Trip Program	
Program Name	**Fast Curve (FC) Settings**
First Deployed	2018
Current Scope	HFTD / HFRA
Devices Used	• Circuit Breakers • Line Reclosers • Current-Limiting Fuses
Protection Summary	• Circuit-specific settings which provide fault energy reduction and a level of coordination between the current-limiting fuses and the circuit breakers and/or line reclosers • Phase and ground pickup elements set to a multiple of the device minimum trip no less than 2.3 times for phase and 5 times for ground • Phase and ground pickups set to detect faults out to end-of-zone (downstream protection recloser/fuse or end of line) protective device • 50P and 50N definite time elements set to 4 cycles which provides fast operation to reduce fault energy while still providing coordination with downstream fuses
Activation Criteria	Fast curve settings activated in the event of any of the following: • Red Flag Warning declared by National Weather Service • Fire Weather Threat declared by SCE Weather Service • Fire Climate Zone declared by SCE Weather Service • Thunderstorm Threat declared by SCE Weather Service

SCE's Fast Trip Device Protection Overview

Fast curve makes our system devices more responsive to wildfire risks by…

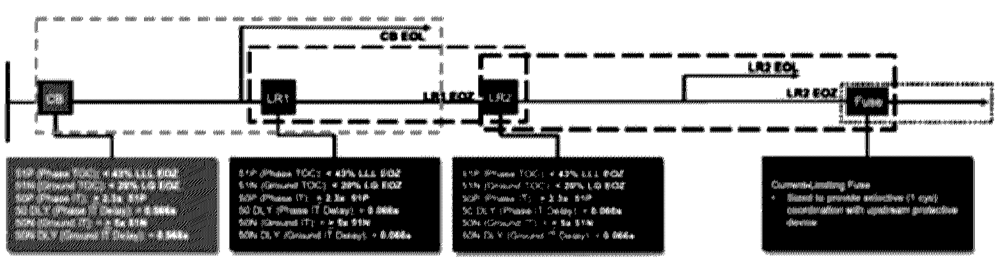
Faster Fault Detection
Faster trip settings detect distribution primary faults more quickly to reduce incident fault energy

Use of Current-Limiting Fuses
Use of current-limiting fuses reduce fault energy up to 25 times which lessens incandescent particles and wire down

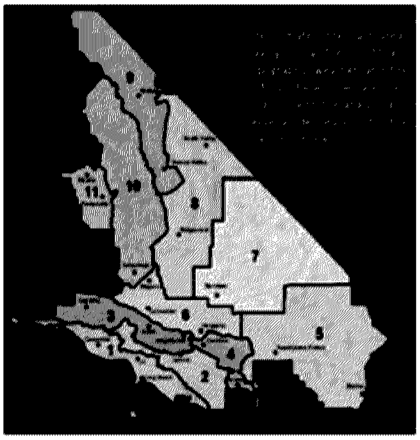
Reducing Total Fault Energy
Fast curve reduces risk of initial fault impact (wire down) by limiting the fault energy

Fast Trip Device Protection

- Fast curve settings make use of previously unused instantaneous/definite time overcurrent elements within the relays which are locally or remotely enabled
- Normal relay settings are always active and don't change even if the fast curve settings are enabled or disabled
- Fast curve settings are disabled during energization of a circuit or circuit section following a patrol to avoid inrush trips
- Fast curve-enabled line reclosers and/or current-limiting fuses are strategically placed near HFRA boundaries and may allow fast curve settings to be disabled on upstream non-HFRA circuit sections
- Use of fast curve-enabled line reclosers and current-limiting fuses reduces the outage area and subsequent patrol times



SCE's Fast Trip Enablement Event-Driven Criteria



Activation Criteria Overview

SCE enables fast curve settings for equipped devices on impacted circuits and circuit sections that traverse HFRA in the event of any of the following:

- **Red Flag Warning** declared by National Weather Service
- **Fire Weather Threat** declared by SCE Weather Services
  - Circuit conditions forecasted for Fire Potential Index (FPI) greater than or equal to 11 and wind speeds greater than or equal to 31 mph sustained and/or 46 mph gust
- **Fire Climate Zone Threat** declared by SCE Weather Services
  - Seasonal approach based on zone-specific historical occurrence of fuel-driven fires
- **Thunderstorm Threat** declared by SCE Weather Services
  - Weather models predicting 30% or higher chance of dry lightning occurring over HFRA area

SCE's Outage Response & Restoration

Outage Response & Restoration	
Outage Response Target	60 minutes. Fast curve activations receive similar treatment to trouble calls in high fire risk areas and take top priority.
Dedicated Response Crews & Resources	Although resources are not dedicated specifically for fast curve settings: • Additional crews may be put on standby associated with storm conditions or leading up to PSPS events as needed • Helicopter patrols and drones are leveraged for difficult-to-access locations
Automatic Testing / Reclosing / Step Restoration	• Automatic reclosing is disabled upon declaration of Red Flag Warning, Fire Weather Threat, Fire Climate Zone and/or Thunderstorm Threat conditions in high fire risk areas • Patrol is required prior to re-energization and step restoration is performed
Fault Indicators	• SCE has both mechanical and remote-monitored fault indicators; 4,200+ installed in high fire risk areas • Even with the presence of fault indicators, SCE requires all high fire circuitry which is de-energized following a fault to be patrolled before re-energizing during elevated fire weather and fuel conditions
Fuse Savers	• Fuse savers are not part of SCE's current fast curve strategy
Outage Customer Support & Communications	• SCE does not alter communication to customers when fast curve settings are enabled • Customers receive standard repair outage alerts and updates through their preferred channel and outage details are also updated on SCE's Outage Map at sce.com/outagemap

SDG&E Fast Trip Setting Program

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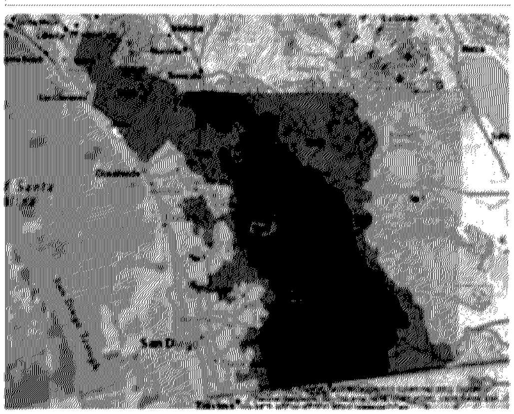
SDG&E Service Territory Overview

SDG&E HFTD Districts



SDG&E Service Territory Overview	
Service Area	4,100 square miles
Customers	3.7M people through 1.5M electric meters
Distribution Circuit Miles	17,401
Transmission Circuit Miles	1,995
Service Territory Description	64% of service territory within HFTD.

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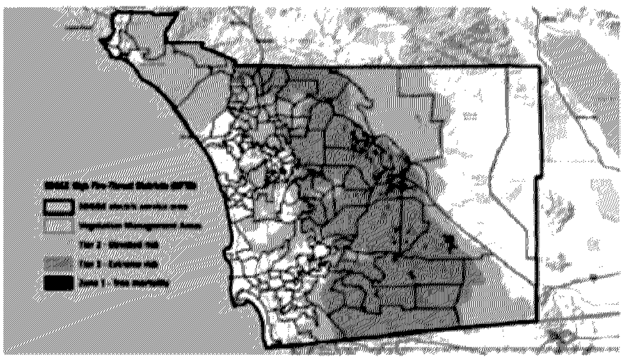
SDG&E's Fast Trip Program Summary

SDG&E HFTD Districts



Fast Trip Program	
Program Name	**SRP: Sensitive Relay Profile**
First Deployed	2011
Current Scope	RFW / PSPS
Devices Used	• Circuit Breakers • Line Reclosers • Pad mounted fault interrupters
Protection Summary	• Setpoint for SRP is determined by reviewing a 5-year load trend for phase and ground over SCADA • Phase element is set by 150% of peak load • 85% coordination factor with adjacent SRP devices, but also prioritize reaching EOL • All reclosers lock out on initial trip • Devices are set to clear instantaneously with .5 cycle delay
Activation Criteria	• Extreme FPI • Forecasted PSPS events

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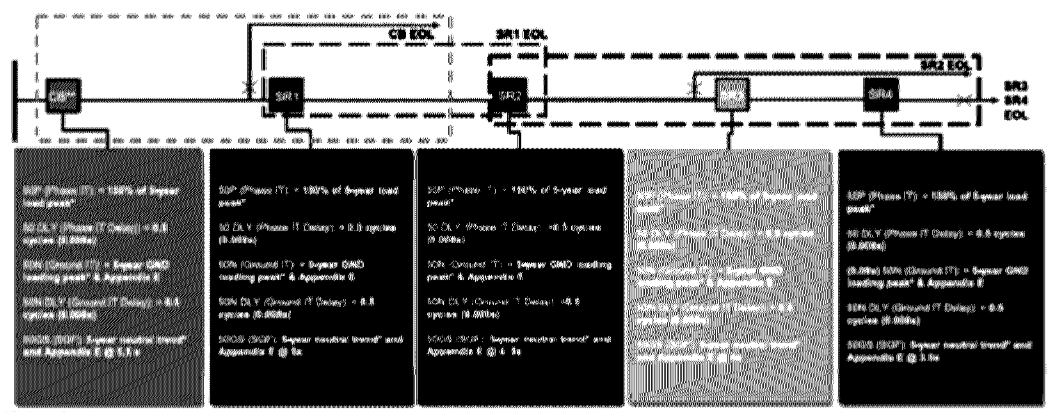
SDG&E's Fast Trip Device Protection Overview

Fast Trip Device Protection
• SDG&E has been deploying Fast Trip Settings for over 10 years, referred to as Sensitive Relay Profile (SRP)



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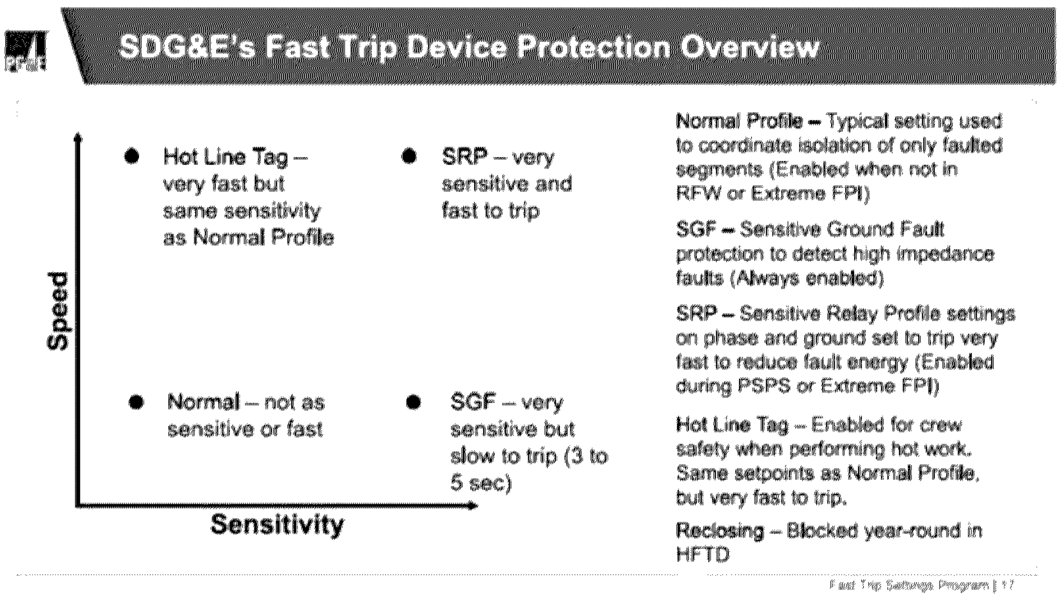
SDG&E's Fast Trip Device Protection Overview
Hot Line Tag – very fast but same sensitivity as Normal Profile
SRP – very sensitive and fast to trip
Normal – not as sensitive or fast
SGF – very sensitive but slow to trip (3 to 5 sec)
Speed
Sensitivity
Normal Profile – Typical setting used to coordinate isolation of only faulted segments (Enabled when not in RFW or Extreme FPI)
SGF – Sensitive Ground Fault protection to detect high impedance faults (Always enabled)
SRP – Sensitive Relay Profile settings on phase and ground set to trip very fast to reduce fault energy (Enabled during PSPS or Extreme FPI)
Hot Line Tag – Enabled for crew safety when performing hot work. Same setpoints as Normal Profile, but very fast to trip.
Reclosing – Blocked year-round in HFTD
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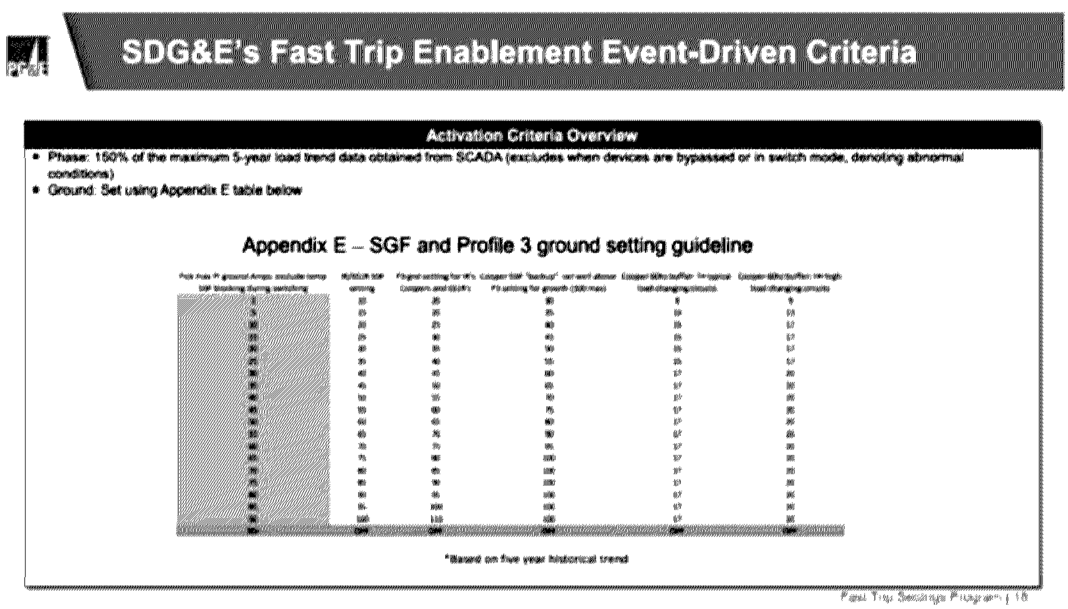
SDG&E's Fast Trip Enablement Event-Driven Criteria
Activation Criteria Overview
Phase: 150% of the maximum 5-year load trend data obtained from SCADA (excludes when devices are bypassed or in switch mode, denoting abnormal conditions)
Ground: Set using Appendix E table below
Appendix E – SGF and Profile 3 ground setting guideline
*Based on five year historical trend
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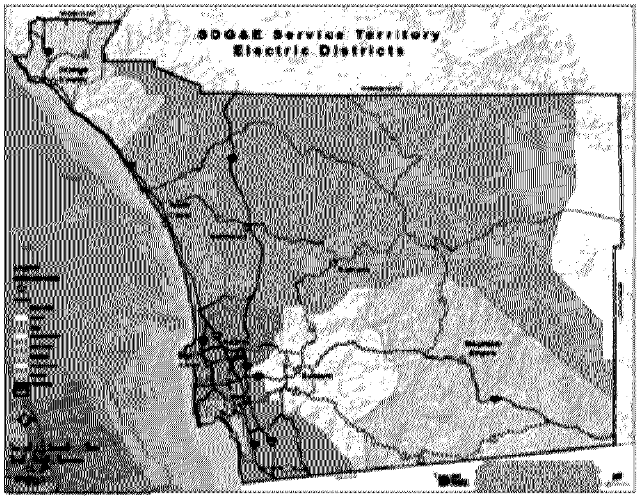
SDG&E's Fast Trip Enablement Event-Driven Criteria



Activation Criteria Overview

Sensitive Relay Settings will be enabled for on devices as described below:

- If the FPI is Extreme in Mountain Empire and/or Ramona, Tier 3 should have Sensitive Relay Settings enabled
- If the FPI is Extreme in Eastern and/or Northeast, the entire HFTD (Tier 2 and Tier 3) should have Sensitive Relay Settings enabled
- If the FPI is Extreme in Orange County, then the HFTD in Orange County should have Sensitive Relay Settings enabled
- If the FPI is Extreme in any of the San Diego County coastal districts (North Coast, Beach Cities, Metro) all the Coastal Circuits with Fire Risk should have Sensitive Relay Settings enabled

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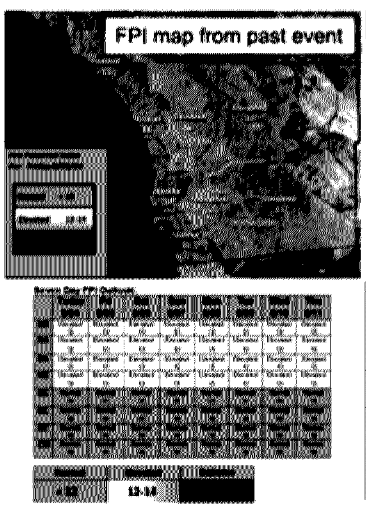
SDG&E's Outage Response & Restoration



Outage Response & Restoration	
Outage Response Target	**60 minutes**
Dedicated Response Crews & Resources	• During Extreme FPI / PSPS Events, dedicated crews staffed for restoration and readiness response • Line SCADA crews are staffed 24/7 ready to respond to collect relay event records. • Records are sent to System Protection Engineering for review • Records help determine proper operation and help with determining fault location • Feedback from Engineering provided to the operations teams for better situational awareness
Automatic Testing / Reclosing / Step Restoration	• Protocols for testing / reclosing / restoration are no different between SRP and non-SRP conditions when under Extreme FPI / PSPS conditions • Automatic testing is not performed, and reclosing is disabled • Patrol is required and step restore is performed for all outages
Fault Indicators	Fault indicators provide visual or remote indication of faults on the system – SDG&E plans to deploy these to quickly identify hazards and improve restoration times. **SDG&E's 2022 Plan Includes:** • Install 300-500 units on targeted locations by end of year • Prioritize HFTD and WUI (Wildland Urban Interface) circuits based on results of sensitive relay outages • Along circuits, install on bifurcations or midway on non-SCADA conductor sections, where facilities enter areas of high fuel concentrations, difficult to patrol areas, or transitions between HFTD tiers, overhead and underground unfused transitions, and downstream of non-SCADA substations.
Fuse Savers	SDG&E is currently not planning on deploying any fuse savers on our system.
Outage Customer Support & Communications	SDG&E does not alter communication to customers when SRP is enabled. • Outage response is no different for SRP outages versus non-SRP outages during an event

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APPENDIX C: MODES OF OPERATION FOR SUBSTATION BREAKERS AND LINE RECLOSERS ON OVERHEAD DISTRIBUTION CIRCUITS

This section provides NV Energy's operating protocols for five different operating modes.

Modes of Operation
for
Substation Breakers and Line Reclosers
on
Overhead Distribution Circuits

Automatic "Auto" Mode

Having a circuit breaker or recloser in "Auto" mode refers to the AUTO/MANUAL handle, switch, push button, etc. for the device being in the "AUTO" position. In this mode, overhead distribution circuits have automatic reclosing enabled. Automatic reclosing refers to the capability of the device to close automatically after it trips (opens for a fault or overload). Typical settings in Northern Nevada call for three trips to lockout (stay open). The normal sequence is 1st trip, reclose after time delay, 2nd trip, reclose after time delay, 3rd trip with lockout. Northern Nevada often refers to these operations as "trip and reclose" or "trip to lockout", while southern Nevada often refers to "relay and reclose" or "relay to lockout". The device may have settings that enable fast curves (aka "fast trips") for the first trip with delayed curves (aka "slow or delayed trips") enabled for any subsequent trips. The practice of enabling fast curves is also referred to as "fuse saving" as the intent is to have the device trip and reclose for a temporary problem before a lateral fuse can operate. While fuse saving was common at one time, most circuits are now normally operated with only delayed curves enabled as it is more desirable to have a permanent outage on a lateral due to a blown fuse than have a nuisance momentary outage on the mainline due to a trip and reclose operation.

Manual Mode

Having a circuit breaker or recloser in "Manual" mode refers to the AUTO/MANUAL handle, switch, push button (labeled "Manual When Lit"), etc. for the device being in the "MANUAL" position. In this mode, overhead distribution circuits have automatic reclosing blocked (disabled), so the device will trip only once and then lock out. The device will operate according to whatever curves are normally enabled in Auto for the first trip, which usually are delayed curves. Fast curves are not typically enabled automatically when a device is placed in Manual, but some devices like the Cooper Form 4 recloser controller do have this feature. Devices that have fast trip fire mode (FTFM) capability as described below automatically disable fast trips when put in Manual.

*Note: Most newer circuit breakers and reclosers that have SCADA can be switched remotely by system control between Auto and Manual modes.

Hot Line Tag

This mode refers to a "Hot Line" tagging relay being enabled either via SCADA or local push button, switch, etc. at the device. In this mode, automatic reclosing is blocked and instantaneous tripping is enabled, so the device will trip to lockout using instantaneous settings. For the most part, coordination with reclosers and fuses downstream from the device is lost in this mode.

Seasonal Fire Mode

When a device is in "Seasonal Fire Mode", automatic reclosing is blocked and normal delayed curves are enabled, so the device will operate using delayed curves before tripping once to lock out. This means coordination with reclosers and fuses downstream from the device is maintained in this mode. Seasonal fire mode has typically been enabled either via SCADA or local push button, switch, etc. at the device. It should be noted that as fast trip fire mode (FTFM) capability is expanded through the system, these push buttons, switches, etc. will be repurposed to enable FTFM at devices and relabeled accordingly. When this occurs, seasonal fire mode can be achieved by placing the device in Manual (which will block reclosing and disable fast trips as described above).

Fast Trip Fire Mode (New for 2023)

This refers to "Fast Trip Fire Mode" (FTFM) logic being enabled either via SCADA or local push button, switch, etc. at the device. In this mode, automatic reclosing is blocked and definite-time trip settings are enabled, so the device will trip and lockout within approximately 0.1 seconds. Partial coordination with reclosers and fuses downstream from the device can be expected in this mode. Improved coordination can be achieved by enabling instantaneous tripping on downstream line reclosers and/or Trip Savers.

A Note on Hot Line Permits

As part of system control issuing a "Hot Line Permit", reclosing must be disabled. There is no requirement to enable fast trips. As such, a "Hot Line Permit" can be issued when the device is in any of the operating modes described above except "Auto".

It is possible to apply/enable multiple modes simultaneously. For example, a device can have FTFM enabled and have a hot line tag applied. In these situations, tripping time is determined by whichever settings are the fastest. In general, trip times for the various modes from fastest to slowest will be:

1. Hot Line Tag (instantaneous tripping)
2. Fast Trip Fire Mode (definite time tripping) **or** Manual with fast curves (uncommon)
3. Seasonal Fire Mode (delayed curves) **or** Manual with delayed curves (common)

APPENDIX D: TIER 3, 2, 1E RELAY CAPABILITIES

Circuit	Tier (or highest tier if multiple)	Relay Type	Relay Model	Relay itself capable of daily fast tripping? (does not address SCADA)	Comments	Substation Engineering Needed?	Replace with	Assignment	Difficulty	Price (w/ external crew)	Price (w/ only internal crew)	Crew Times	Site Name	Comm Difficulty (1-Easy, 3-Hard)	Comm Cost	Supporting Documents	Telecom Scope	Substation Scope
[illegible]																		

APPENDIX E: TABLE OF ACRONYMS

This Appendix identifies the acronyms used in this document

CB	Circuit Breaker
CCP	Covered Conductor Pilot
CRI	Composite Risk Index
FTFM	Fast Trip Fire Mode
HLT	Hot Line Tag
IOU	Investor-Owned Utility
LCB	Legislative Council Bureau
NDPP	Natural Disaster Protection Plan
OMAG	Operations, Maintenance, Administrative, and General
PDZ	Proactive De-energization Zone
PSOM	Public Safety Outage Management
SCADA	System Control and Data Acquisition
SRP	Sensitive Relay Profile

Appendix B: Emergency De-Energization Wildfire Policy (Redacted)

This confidential section contains NV Energy’s Emergency De-Energization Wildfire Policy.

Emergency De-Energization Wildfire Encroachment Natural Disaster Protection and System Operations Procedure 4920

Author	**Alexander Hoon**
Owner, VP Electric Delivery	**Jesse Murray**
Approval, President, and CEO	**Doug Cannon**
Approval, VP, Electric Delivery and NDPP	**Jesse Murray**
Approval, VP Transmission	**Scott Kaufmann**
Authorizing Department	**Transmission**
Approved Location	
File Number-Name	
Revision Number	**1.0**
Revision Date	**9/6/2024**
Summary of Policy	**Wildfire Encroachment Action Description**
Affected Departments	**Grid Operations, Electric Delivery and Natural Disaster Protection (Power Safe)**
Effective Date	**9/6/2024**

	Confidential	**X**	**Internal**
	Restricted		**External**
			BES Cyber System Security (BCSI)

0	**7/3/24**	**Approved Policy**
1.0	**9/6/24**	**Clarifying revisions**

Emergency De-Energization Wildfire Encroachment Natural Disaster Protection and System Operations Procedure 4920

Table of Contents

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1. PURPOSE

This document defines Sierra Pacific Power Company dba NV Energy and Nevada Power Company dba NV Energy's (together, "NV Energy" or "NVE") escalation and response protocols when a wildfire is approaching NV Energy owned or operated transmission and/or distribution facilities. As set forth in Section 2, this procedure requires de-energization of facilities when a wildfire encroachment occurs within defined distances to NV Energy facilities.

2. REFERENCES

ESCC 4910	Fire Season Operating Procedure
	NDPP Wildfire Season Operations Plan
	NDPP: Emergency De-Energization Reactive Comms Plan
	NDPP: Emergency De-Energization Proactive Comms Plan

3. COMMON ACRONYMS

See Appendix D.

4. DEFINITIONS

Wildfire encroachment – means an active wildfire that is uncontrollable and unpredictable and is at risk of encroaching established safety boundaries from electric facilities thereby increasing the risk of additional ignitions if the fire impacts energized facilities. Safety distances are pre-defined and encroachment occurs when a uncontrollable and unpredictable wildfire is within the safety distances from facilities outlined in this policy.

Uncontrollable and unpredictable – is generally defined as an active wildfire that has moved beyond the immediate area of ignition and exceeds the capabilities of current suppression activities. A wildfire may not be uncontrollable and unpredictable if fire control measures have mitigated the threat of the wildfire's continued spread, for example where responding agencies have implemented a fire line that is effectively preventing the wildfire's spread toward electric facilities or where the fire's behavior otherwise demonstrates that it is not progressing in the direction of the electric facilities. For avoidance of doubt, unless there is credible information confirming that the threat of spread is mitigated, the fire is deemed to be uncontrollable and unpredictable.

Electric facilities – includes overhead facilities, such as conductors, equipment on poles, substations and generation facilities.

5. SCOPE

Wildfires can spread and move quickly based on many variables. This procedure outlines emergency de-energization of transmission and distribution facilities to minimize additional fire ignitions and to support emergency response activities. The policy outlines the boundary distances for de-energization, a standardized process checklist for re-energization and the reporting and communication protocols used to facilitate this enhanced emergency response measure.

6. IMMEDIATE ACTION: DUE TO FIRE LOCATION RELATIVE TO FACILITIES

The NV Energy on-call Fire Duty Officer, in consultation with NV Energy's meteorologist, is responsible for monitoring any wildfires. The on-call Fire Duty Officer may monitor for and learn of new wildfires through reporting from external sources and through monitoring of internal tools (i.e. wildfire cameras, satellite wildfire hot spot warning, or other application alerts).

Outside of normal business hours, System Operators shall promptly notify the on-call Fire Duty Officer by telephone upon receiving notice of any new wildfire [redacted] of an NV Energy facility.

Multiple technologies (wildfire cameras, and satellite hot spot detection, etc.), fire agency information, and external, and internal observations, will be monitored, and used to support early credible wildfire detection and determination of general size and location of the fire. If there is credible information that the wildfire is within the encroachment boundary distance and deemed uncontrollable and unpredictable then the NV Energy facilities within the wildfire encroachment boundary shall be de-energized pursuant to the guidelines presented in Table 1 as quickly as is feasible, with a maximum [redacted] assessment period from the time of an initial report to NV Energy, taking into account the specific circumstances and impacts of a particular event. This includes joint- or foreign-owned facilities under the operational control of NV Energy (example cases are provided in Appendix C to help clarify edge cases).

Sources for credible wildfire information within the distance and timeline threshold established, include but are not limited to 911, Transmission & Distribution ("T&D") field operations, Emergency Management, on-call Fire Duty Officer, Grid Operations, Reliability Coordinator, and Customer Operations. Additional sources that possess information about the incident may also be acted upon as appropriate. The wind speed information at the fire location or nearest weather station will be obtained using **nvenergy.westernweathergroup.com** before de-energization to determine which wildfire encroachment boundary applies. **However, when weather data is not available or in doubt, the on-call Fire Duty Officer will utilize all available sources of information to determine course of action based on the criteria within Table 1.**

In the event of a wildfire encroachment and after a maximum [redacted] assessment time, subject facilities will be de-energized. A wildfire encroachment has occurred if there is credible information that a wildfire encroachment has breached the minimum safety distance in the table below.

Table 1 – Identified Wildfire Risk Level and Encroachment Boundary Distances

Severe Fire Danger Index Rating (SFDI)[1]	Sustained Wind Speed (mph)[2]		
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		
Moderate (non-Fire Tier)	[redacted]		
Moderate (Fire Tier areas)	[redacted]	[redacted]	[redacted]
High	[redacted]	[redacted]	[redacted]
Very High	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		

NOTE: The distances in Table 1 are based on the fact that it will take some time for the System Operator to assess the data coming in and study the potential impacts before de-energizing. The expectation is that it will take [redacted] to perform those actions and then begin the de-energization [redacted], however, additional time may be required depending on specific circumstances, including those involving requests for approval from the President & CEO as described below.[4]

The on-call Fire Duty Officer will work with others including Meteorologist, GIS Analyst, etc., to understand the size and location of the fire, current SFDI Rating, wind speed, proximity to facilities, etc. and then will convey that information to the designated System Operator. The System Operator determines whether the de-energization criteria is met, based on the information received.

The designated System Operator is expected to de-energize facilities within the wildfire encroachment area based on available credible information at the time. As the Fire Duty Officer collects data, there could be unique scenarios about the fire and/or de-energization zone. An example could be that the typical de-energization radiuses overlap different SFDIs or tier zones that make the de-energization zone a shape other than a circle. This information can be used by

[1] As defined on the daily SFDI risk matrix on nvfireweather.com/forecast and https://m.wfas.net/dev/wfas_sfwp_map_sacc.php.

[2] Use nvenergy.westernweathergroup.com to determine wind speed.

[3] Use iConnect, ESRI, ArcGIS, etc. to determine approximate distance from fire to NV Energy facility.

[4] Supervisory Control and Data Acquisition.

the Director, Grid Operations and Reliability, Vice President of Electric Delivery, Vice President of Transmission, or Incident Commander may issue additional specific instructions related to a de-energization, such as the actual de-energization boundary, the specific time or sequence of de-energization. In the absence of a contrary instruction from management, however, a System Operator is expected to de-energize and shall complete the de-energization as required by Table 1 in instances of wildfire encroachment.

If transmission facilities are identified within the de-energization zone, the System Operator shall study the impacts using the RTCA tool to identify impacts and plan for any required mitigation. [redacted]

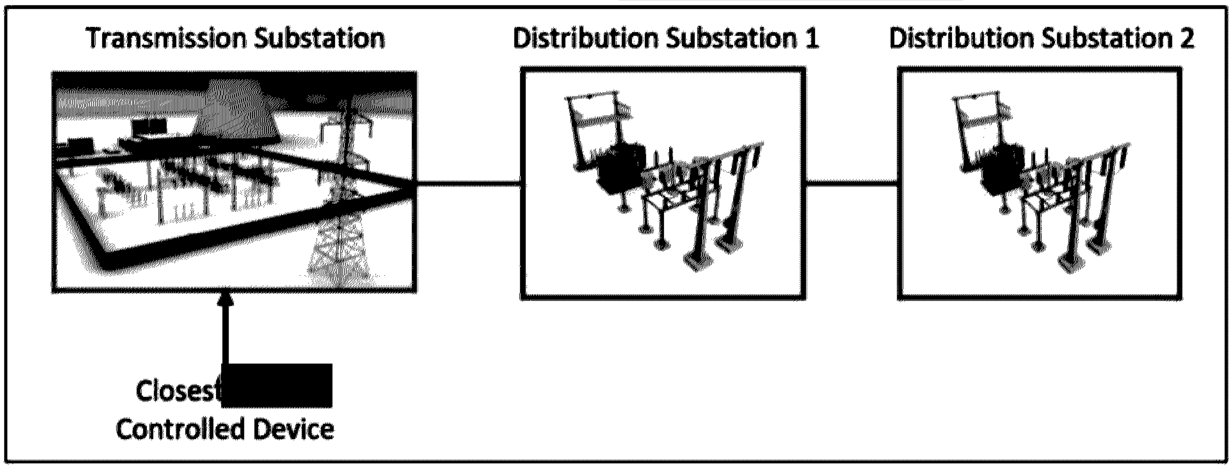
Localized de-energization will be executed without prior notice from leadership. Localized events generally range from individual distribution circuits up to a full substation de-energization including associated transmission lines. System Operators will notify Vice President, Transmission (or an authorized delegate) when it is anticipated that de-energization may result in elevated system impacts, as described below.

For elevated impacts and depending on the specific circumstance of an event, the Vice President, Transmission (or an authorized delegate) may notify the President & CEO to provide the opportunity to direct that some or all electric facilities remain in service despite a wildfire encroachment. In such circumstances, one attempt will be made to contact the President & CEO, or the authorized delegate, to seek approval to keep facilities in service despite an identified wildfire encroachment. If contact is not successful, then the full de-energization radius will be executed. Only the approval of the President & CEO of NV Energy, or a delegate authorized in writing, is authorized to keep facilities energized if a wildfire encroachment has occurred. Examples of situations where facilities might remain energized notwithstanding a wildfire encroachment might include public safety or system stability.

The System Operator is expected by this procedure to act as quickly as feasible and ***shall de-energize*** all electrical facilities supporting transmission and distribution facilities within the wildfire encroachment boundaries outlined in Table 1 via the closest [redacted] device. Additionally, if NV Energy does not obtain credible information until the fire is already inside the right-of-way, then that facility shall be de-energized as quickly as feasible, even if the size is less than the applicable [redacted] thresholds. In some cases, de-energization from the closest available [redacted] device may result in the initial de-energization of a larger number of facilities to achieve the quick [redacted] outage to a smaller target.

For example, opening only a substation distribution circuit breaker could satisfy the wildfire encroachment de-energization, but the closest [redacted] device is at a transmission substation that will de-energize two substations. In this case, even though more customers will be impacted, activating an open point [redacted] is required to complete de-energization as shown in Figure 1. Once personnel are available and visual assessment has been verified, the System Operator has authority to begin restoration pursuant to the re-energization guidelines in Section 11 of this policy. Facilities that did not require de-energization but were subsequently de-energized as a result of the location of the nearest [redacted] device, may be restored once that visual assessment has been made.

Figure 1 – Wildfire Encroachment [redacted] Protocol



The following actions will occur immediately following de-energization:

Trouble Dispatcher:

1. Trouble Dispatcher will dispatch field personnel to the site to assess the situation.
2. Trouble Dispatcher will notify the on-call T&D Operations Manager

System Operator

1. System Operator will mitigate any contingencies noted during the assessment or contingencies that show up in real time.
2. System Operator will follow normal operating procedures, including contacting and informing other impacted utilities of the situation (i.e., Reliability Coordinator (RC), neighboring TOPs, Public Utility Districts, IOUs, generators, etc.).
3. System Operator will place close inhibit tags on applicable breakers.
4. System Operator will log the actions taken in iTOA.

T&D Operations Manager

1. T&D Operations Manager will notify the on-duty Emergency Manager at the 24/7 number. If the on-duty Emergency Manager is not already engaged on work related to the specific wildfire, advise them of the de-energization/area impacted and wildfire location.
2. T&D Operations Manager will file an [redacted] form depending on impact of any such de-energizations if needed.

Fire Duty Officer

1. The on-call Fire Duty Officer will start the Wildfire Threat Tracking Form with the initial wildfire information, including but not limited to, how the information was received (field personnel, 911, Fire Duty Officer, Emergency Management, etc.), when it was received, and status of the general location based on field verification by "job title" (Step 1), impact information (substations, circuits, customer numbers, etc.) and any other data required to report and track event history.

Real Time Analytics Engineer

1. The Real Time Analytics Engineer ("RTA") will mark all resulting outages with the following.
   - Cause Type: Forced
   - Subtype: Distribution or Transmission
   - Category: Nature
   - Cause: Fire Encroachment

   The codes above will result in an outage message to customers of "Shutdown for Fire Encroachment" and "A wildfire is in the vicinity of NV Energy's electrical equipment and power has been shut off to allow a safe response." RTAs will need to enter these cause codes within approximately five minutes of the start of the outage so that the information is presented in the emails to customers.

   The estimated time of restoration ("ETR") can remain blank for these outages. Once more information is known from the field teams and/or Incident Management Team ("IMT"), the RTA should update the ETRs for individual outages.

Emergency Manager

Upon notification of the de-energization, the on-duty Emergency Manager shall do the following:

1. Emergency Manager will notify on-call IMT Incident Commander ("IC"), Public Information Officer ("PIO"), and Meteorologist.
   a. Determine the need to activate the IMT based upon review of external notifications received from emergency responders and fire simulations. The IMT should only be activated if the de-energization is of a size or complexity beyond that normally handled by routine operations, as per the Corporate Emergency Response Plan.

b. Create and distribute External Notifications to key impacted stakeholders including, but not limited to:
   i. Public Utility Commission of Nevada ("PUCN");
   ii. State, county, city and local official;
   iii. Emergency Managers;
   iv. Impacted telecommunication providers; and
   v. Major Accounts.

The on-call Fire Duty Officer will engage with the fire Incident Command Post to understand the full situation and begin the re-energization evaluation using the Re-Energization Checklist (see Appendix B).

7. IMMEDIATE ACTION: DE-ENERGIZATION REQUESTS

Pursuant to current protocol, if local fire personnel, or an Incident Commander request the de-energization of facilities, the System Operator will de-energize the facilities as soon as feasibly possible using the closest upstream [redacted] device or other field device depending on circumstance. Upon de-energization, the System Operator will follow the steps outlined in Section 6 of this procedure.

When local fire personnel or incident command request de-energization of facilities, the System Operator will clarify the timeframe requested (i.e. immediate, 15 minutes, 1 hour, etc.). If time allows, the System Operator will notify the RC of the impending action, complete contingency analysis [redacted] and plan post contingency actions. If the fire suppression authorities request an immediate de-energization, and time does not allow studying the impacts first, then the System Operator will immediately de-energize the facility(ies) and then subsequently notify the RC if required, verify whether there are any impacts to the system, and then resolve those impacts.

Facilities that are de-energized pursuant to a request from local fire personnel or an Incident Commander shall be re-energized pursuant to the process outlined in this policy if those facilities would have otherwise been de-energized under the policy absent a request.

8. MONITORING AND REPORTING: NON-IMMEDIATE ENCROACHMENT

The NV Energy on-call Fire Duty Officer, in consultation with NV Energy Meteorology, is primarily responsible for monitoring any wildfires. The on-call Fire Duty Officer may monitor for and learn of new wildfires through reporting from external sources and through monitoring of internal tools (i.e. wildfire cameras, satellite wildfire hot spot warning, or other application alerts).

Outside of normal business hours, System Operations shall promptly notify the on-call Fire Duty Officer by telephone upon receiving notice of any new wildfire within [redacted] of any NV Energy facilities.

If the wildfire fire encroachment may impact Bulk Electric System (BES) elements or if a proactive de-energization occurs on a BES element, then the Transmission Operator shall notify and coordinate with RC West [redacted]

The following provides guidance on how/when to respond to fires that are outside the immediate de-energization criteria from Table 1.

- **More than [redacted].** Wildfires more than [redacted] miles from the nearest NV Energy facilities will be monitored for potential growth and potential impact by the on-call Fire Duty Officer. If the wildfire movement is in the direction of company facilities and/or is growing, a regular communication cadence to internal company personnel on the wildfire status will be established by the IMT.

- **Greater than [redacted] up to [redacted] miles.** The on-call Fire Duty Officer shall notify by phone call the Director, Grid Operations and Reliability or an authorized delegate (who may escalate such information through normal channels, including the on-call IMT) of any new wildfire that is between [redacted] and [redacted] miles of NV Energy facilities.

- **Within [redacted] miles, but smaller than [redacted] in grass/brush or less than [redacted] in timber.** The on-call Fire Duty Officer shall notify by phone call the Director, Grid Operations and Reliability or an authorized delegate (who may escalate such information through normal channels, including the on-call IMT) of any new wildfire that is between less than [redacted] miles of NV Energy facilities.

- **Severe Fire Danger Index ("SFDI") is less than extreme.** Wildfires may be outside of the de-energization circle based on the wind speed but should still be monitored by the Fire Duty Officer. As an example, if a fire is within [redacted] miles when SFDI is high and wind speed is 5 mph then no immediate de-energization is needed but the wildfire will be monitored. The on-call Fire Duty Officer shall notify by phone the Director, Grid Operations and Reliability or an authorized delegate (who may escalate such information through normal channels, including the on-call IMT).

- **Preliminary Spread Assessment.** Upon receiving notice of a new wildfire, the on-call Fire Duty Officer will promptly obtain a preliminary spread assessment from the on-duty meteorologist regarding the probability of the fire damaging NV Energy facilities and shall supplement the original email notification to the Director, Grid Operations and Reliability or an authorized delegate with the preliminary spread assessment, as soon as it is available. If the preliminary spread assessment indicates that the fire will likely reach NV Energy facilities at any time prior to the end of the next business day, the on-call Fire Duty Officer will promptly telephone the Director, Grid Operations and Reliability or an authorized delegate to confirm receipt of the preliminary spread assessment. Otherwise, the on-call Fire Duty Officer may telephone the Director, Grid Operations and Reliability or an authorized delegate to confirm receipt at the beginning of the next business day.

If a wildfire transitions from a monitoring and reporting condition to a de-energization condition, then the steps in Section 6 will be completed.

9. WILDFIRE THREAT TRACKING

If a preliminary spread assessment concludes that a wildfire will likely grow into the encroachment boundary within 48 hours, the on-call Fire Duty Officer, in consultation with the on-duty meteorologist, shall promptly complete a Wildfire Threat Tracking Form.

If a preliminary spread assessment concludes that wildfire contact with NV Energy facilities is not likely to occur within 48 hours, the on-call Fire Duty Officer will continue to monitor the new wildfire and request a new preliminary assessment if there are any material changes in the fire. The Wildfire Threat Tracking Form generally includes the following information:

- Name of the on-call Fire Duty Officer submitting the report and the time of the report.
- Fire location, including a description of the source of such information.
- Fire size, including a description of the source of such information.
- Proximity to the nearest NV Energy facility(ies), with mapping as appropriate. On-Call GIS Analyst will provide a map of the fire and proximity to nearest NV Energy facility(ies).
- Fire growth assessment will be completed by NV Energy Meteorology, including:
    - Estimated fire growth rate and pattern;
    - Maturity of fire response (initial, extended, major/campaign);
    - Forecasted weather conditions which may impact fire spread;
    - Physical terrain between the fire and the facilities; and
    - Estimated duration regarding when the fire may reach company facilities.
- Other information regarding the fire and the company's potential response, including:
    - Location of company field personnel;
    - Monitoring capabilities of field personnel; and
    - Any communications with fire Incident Command.

The Wildfire Threat Tracking Form is included in Appendix E.

The on-call Fire Duty Officer will promptly transmit the completed Wildfire Threat Tracking Form to the Director, Grid Operations and Reliability or an authorized delegate. After confirming receipt by telephone, the on-call Fire Duty Officer will continue to monitor the wildfire. In conjunction with ongoing monitoring, the on-call Fire Duty Officer shall:

- Open communications regarding status with local fire agencies;
- Coordinate with on-scene field personnel;
- Confer with the on-duty Meteorologist to evaluate fire conditions and update fire spread assessments;
- Update the Wildfire Threat Tracking Form as needed; and
- Manage an ongoing exchange of information between System Operations, Emergency Management, and Meteorology until there is no threat to NV Energy facilities.

10. CUSTOMER AND STAKEHOLDER NOTIFICATIONS

In all cases of a wildfire encroachment de-energization, the Transmission and/or Distribution Operators will provide notice to on-call T&D Operations Manager. The T&D Operations Manager will notify the on-call Fire Duty Officer (if not already aware) and on-call Emergency Manager.

The NV Energy Fire Duty Officer will notify responding fire agencies of the de-energization. The NV Energy assigned Emergency Manager will notify responding emergency managers.

Short duration de-energization notifications will be managed by Major Account Representatives following the same routine for unplanned outages.

Longer duration de-energization will be communicated using the IMT PIO communication process. The PIO is responsible for making external communications to customers with approval from the IMT IC. If time allows before de-energization, the PIO will create communications warning customers of potential de-energization. If time does not allow, a post event customer notification will provide customers information related to the de-energization. The Encroachment Policy Proactive Communication Plan and Encroachment Policy Reactive Communication Plan have been developed and are referenced in Section 2.

11. RE-ENERGIZATION

As information is obtained concerning the wildfire encroachment event, it may be possible to begin re-energizing portions or all the facilities that were initially de-energized.

The System Operator has authority to re-energize under the following conditions:

1. Facilities that were de-energized based on a [redacted] control location; once isolation is in place, the facilities are outside the encroachment boundary and no longer required to be de-energized.
2. On-call Fire Duty Officer has completed the relevant Re-Energization Checklist, has determined that all “YES/NO” questions on the checklist have been answered “YES” and that has been communicated to the System Operator.
3. If the fire did not move through a particular facility’s right-of-way then that particular facility can be re-energized.
4. If the fire did move through the line right-of-way, and the line has been patrolled by Lines/Troubleshooter to ensure no damage needs to be addressed prior to re-energization.

The Re-Energization Checklist is included as Appendix B.

In all other cases, including a Re-Energization Checklist with even a single “NO,” the on-call Fire Duty Officer must obtain authorization to re-energize from the President and CEO or authorized delegate.

The facilities may also be re-energized upon a written request to re-energize from an elected official holding the highest executive office for the jurisdiction, including for example, the governor, mayor, or city/county manager, or upon a written request to re-energize from a fire or police chief for the jurisdiction, in the interest of public safety. This request could come from several sources, but must always be communicated to the Director, Grid Operations who would then communicate it to the System Operator.

12. SITUATIONAL AWARENESS TOOLS

Fire Duty Officers and Specialists, System Operators, IMT, etc. will use the following situational awareness tools for making determinations associated to an encroachment de-energization.

ALERTNevada - Operations – Fire Cameras
NVE Wildfire Map (arcgis.com)
WECC Wildfire Dashboard
Wildland Fire Assessment System – SFDI
Western Weather Group – real time wind speeds

13. EMPLOYEE OBLIGATION

Intentional non-compliance with the requirements outlined in this procedure may result in disciplinary action up to and including termination.

14. TRAINING

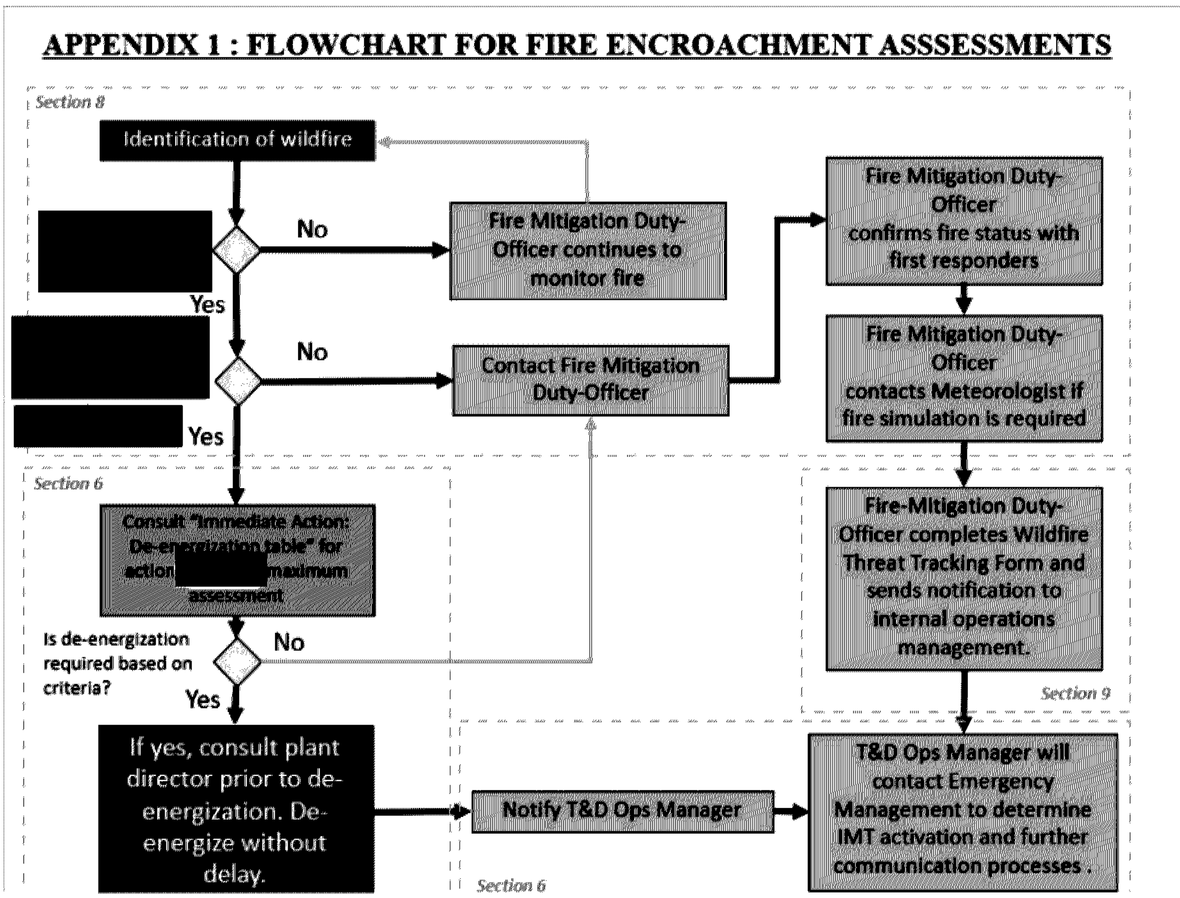
The following personnel shall be trained during the initial implementation and then annually.

- Power Safe (Fire Duty Officers, Meteorologists)
- Grid Operations (Balancing Authority Operators, Transmission Operators, Distribution Operators, Trouble Dispatchers, Real Time Analytics Engineers)
- Lines (Troubleshooters, Linemen)
- Telecommunications
- Substations (Inspectors)
- Generation
- Corporate Communications Specialist

15. PERIODIC REVIEW

This procedure should be reviewed annually and updated as needed.

APPENDIX A: FLOWCHART FOR FIRE ENCROACHMENT ASSSESSMENTS



APPENDIX B: RE-ENERGIZATION CHECKLIST

Incident Name: **Initial Start Time:**
Date: **Current Time:**
Fire Duty Officer:

		RE-ENERGIZE? YES	RE-ENERGIZE? NO	Initials
WEATHER OBSERVATIONS	**ANSWER-COMMENTS**			
Severe Fire Danger Index (SFDI)	*Low, Moderate, High, Very High, or Severe*			
Current Wind Conditions	*Wind Direction, Speed, and Gust*			
Current Weather Conditions	*Rain, Thunderstorms, Sunny, etc.*			
Does current and expected fire weather and fire behavior conditions make it safe to re-energize?				

Is the Wildfire 100% contained? If yes, complete checklist A. If no, complete checklist B.

WILDFIRE OBSERVATIONS	**ANSWER-COMMENTS**			
CHECKLIST A				
• **If wildfire is 100% contained, fill out section below:**				
Who confirmed?				
On-site Field Personnel Name	*Name:*			
On-site Fire Agency Name	*Name:*			
On-call Fire Duty Officer	*Name:*			
Other Name and Agency	*Name and Agency:*			
Can damaged facility(ies) be isolated to support safe restoration?				
CHECKLIST B • **If wildfire is NOT 100% contained, fill out section below:**				
Field Observation Fuel Type	*Grass, Brush, Timber, Litter, etc.*			
Field Observation Terrain	*Flat, Steep, Combination, etc.*			
Is the wildfire moving away from facility(ies)?				
Direction of movement	*N, NE, E, SE, S, SW, W, NW?*			
Are fire agencies at scene?				
On-site Fire Agency	*Name (if known and if multiple agencies just indicate multiple)*			
Are effective fire control measures in place from responding agencies that	*Fire control measure, Name and Agency*			

have resulted in mitigating the threat of impact to facilities? Who confirmed?				
Can facility(ies) not in the path of the wildfire be safely re-energized? *Isolation of the facility(ies) in the path of the wildfire may support some level of restoration.*				
Can damaged facility(ies) be isolated to support safe restoration?				

NOTE: If any of the above YES-NO answers are a "NO", then the President and CEO (or an authorized delegate) approval is required to re-energize.

______________________ **Approval Signature**

___________________________**Approval Title**

APPENDIX C: EXAMPLES OF JOINT-OWNED OR CONTROLLED FACILITIES

Director, Grid Operations should contact the third parties listed below ahead of each season to notify them about this procedure.

Southern Nevada

- Crystal – McCullough 500 kV: NVE is 26.1% owner. Los Angeles Department or Water and Power (LADWP) is the majority owner and has operational control. Both LADWP and NVE do have the ability to control the Crystal breakers through SCADA.
- Crystal – Navajo 500 kV: NVE is 26.1% owner. LADWP is the majority owner and has operational control. Both LADWP and NVE do have the ability to control the Crystal breakers through SCADA.
- Harry Allen – Eldorado 500 kV: NVE is 20% owner. CAISO has operational control. [redacted]
- Harry Allen – Red Butte: NVE owns and controls from Harry Allen to the Utah state line.
- Southern California Edison (SCE).
- PacifiCorp (PAC).
- Western Area Power Administration (WAPA).
- Overton Power District.
- Lincoln County Power District.
- Valley Electric Association (VEA).
- Lead lines to generation plants or loads: NVE generally owns to the first switch outside the [redacted]

Northern Nevada

- Bonneville Power Administration (BPA)
- Pacific Gas and Electric (PG&E)
- PacifiCorp (PAC)
- Idaho Power (IPC)
- Southern California Edison (SCE)
- LADWP
- Liberty Utilities
- City of Fallon
- Truckee Donner Public Utility District (TDPUD)
- Plumas-Sierra Rural Electric Co-Op (PSREC)
- Mt Wheeler Power
- Wells Rural Eelctric Company (WREC)

[end]

APPENDIX D: TABLE OF ACRONYMS

BES	Bulk Electric System ≥ 100 kV
CAISO	California Independent System Operator
CEO	Chief Executive Officer
DMS	Distribution Management System
EOC	Emergency Operations Center
ESCC	Electric System Control Center (Grid Operations)
IC	Incident Commander
IMT	Incident Management Team
IOU	Investor-Owned Utility
PIO	Public Information Officer
PUD	Public Utility District
RC	Reliability Coordinator = RC West
RTCA	Real Time Contingency Analysis
SCADA	Supervisory Control and Data Acquisition
SFDI	Severe Fire Danger Index
T&D	Transmission and Distribution

APPENDIX E: WILDFIRE ENCROACHMENT TRACKING FORM

ACHForm Name	Wildfire Threat Tracking Form
Form Published Date	June 24, 2024
Version	1

1. Report Information

Date / Time of Report	

2. Fire Information

Fire Location (Including description of the source of information)	
Fire Size (Including description of the source of information)	
Proximity to Nearest Company Asset(s) (Include map as appropriate)	
Description of Threatened Company Assets	

3. Fire Mitigation

Fire Duty Officer	

Communications With Fire Incident Command	

4. Fire Growth Assessment

Meteorologist	
Estimated Fire Growth Rate and Pattern	
Maturity of Fire Response (Initial, Extended, Major/Campaign)	
Forecasted Weather Conditions That May Impact Fire Spread	
Physical Terrain Between The Fire and The Assets	
Estimated Duration Regarding When Fire May Reach Company Assets	

5. Other Information

Status of Company Field Personnel	
Monitoring Capabilities of Field Personnel	

6. Ongoing Monitoring

Update 1	
Date / Time	
Update	
Update 2	
Date / Time	
Update	
Update 3	
Date / Time	
Update	

Appendix C: Mt. Charleston Alternatives Considered

The following table shows the alternatives considered for the Mt. Charleston Rebuild.

SUBSTATION: Northwest / Kyle Canyon / Angel Peak / Canyon

Goal: MITIGATE WILDFIRE RISK IN MT CHARLESTON REGION

OPTION MATRIX

	JUDGING CRITERIA	Option #1	Option #2	Option #3	Option #4	Option #5	Option #6	Option #7	Option #8	Option #9	Option #10	Option #11
High-Level Description of Proposed Substation Configuration		New NW1215 Feeder OH (Tier 1&2) and UG (Tier 3) Segments - following Kyle Canyon Road; UG KC1201	New UG NW1215 Feeder following Kyle Canyon Road; UG KC1201	New NW1215 Feeder OH (Tier 1&2) and UG (Tier 3) Segments - Reconductor existing KC 1201 to Tree-wire or Spacer wire.	Rebuild existing Canyon-AP-KC 34.5kV, Relocate KC Substation, UG Existing KC1201 Circuit	Rebuild existing Canyon-AP-KC 34.5kV, Relocate KC Substation, Reconductor existing KC 1201 to Tree-wire or Spacer wire.	Rebuild Canyon Sub to 138/12kV, convert Canyon-AP-KC from 34.5kV to 12kV, remove AP and KC Substations, UG KC1201	Rebuild Canyon Sub to 138/12kV, convert Canyon-AP-KC from 34.5kV to 12kV, remove AP and KC Substations, Reconductor existing KC 1201 to Tree-wire or Spacer wire.	New Cold Creek 12kV Feeder to AP to KC, remove CY, AP and KC Substations, Reconductor existing KC 1201 to Tree-wire or Spacer wire.	Fire season activated microgrid. Combination of solar PV and propane generators at 50% renewable fraction. Reconductor existing KC1201 to Tree-wire or Spacer Cable. Civil Site improvements at KC Sub.	Fire season activated microgrid. Combination of solar PV, and propane generators at 50% renewable fraction. Civil Site improvements at KC Sub.	Fire season activated microgrid. Combination of solar PV, and propane generators at 80% renewable fraction. Civil Site improvements at KC Sub.
Planning Study Completed		Completed	Completed	Completed	Completed	Completed	Completed	Completed	Completed	TBD	TBD	TBD
APN		Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple
General Location		Kyle Canyon	Kyle Canyon	Kyle Canyon	Kyle Canyon, Angel Peak, Lucky Strike Canyon	Kyle Canyon, Angel Peak, Lucky Strike Canyon	Kyle Canyon, Angel Peak, Lucky Strike Canyon	Kyle Canyon, Angel Peak, Lucky Strike Canyon	Cold Creek, Angel Peak, Lucky Strike Canyon	Kyle Canyon	Kyle Canyon	Kyle Canyon
Current Land Use		Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use	Public and Private Use
Owner		BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private	BLM, US Forest Service, NDOT, Clark County, various private
($) SUBSTATION	Remove KC Substation	$60,000	$60,000	$60,000			$60,000	$60,000	$60,000			
	Rebuild/Relocate KC Substation				$2,300,000	$2,300,000						
	Rebuild Canyon 138/12kV						$2,400,000	$2,400,000				
	Remove Canyon Sub								$100,000			
	Remove Angel Peak Sub						$100,000	$100,000	$100,000			
	New Microgrid Equipment									$10,000,000	$10,000,000	$14,000,000
	Civil Site Improvements KC Substation									$580,000	$580,000	$580,000
	12kV Breaker @ Cold Creek								$140,000			
($) DISTRIBUTION	OH 12kV Tier 1&2 NW1215	$10,764,000		$10,764,000								
	UG 12kV Tier 1&2 NW1215		$27,440,000									
	UG 12kV Tier 3 NW1215	$6,540,000	$6,540,000	$6,540,000								
	OH 12kV Reconductor KC1201 Treewire/Covered Cond.			$5,592,000		$5,592,000		$5,592,000	$5,592,000	$5,592,000		
	UG 12kV KC1201	$56,400,000	$56,400,000		$56,400,000		$56,400,000	$56,400,000				
	Extend UG 12kV KC1201 to New KC Sub Location				$2,400,000	$2,400,000						
	OH 34.5kV Rebuild CY-AP-KC				$16,146,000	$16,146,000						
	OH 12kV Rebuild CY-AP-KC						$13,456,000	$13,456,000				
	OH 12kV New Cold Creek Feeder								$22,050,000			
($) LANDS ROW		$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000	$1,050,000
($) ENVIRONMENTAL		$6,497,900	$6,497,900	$6,497,900	$6,497,900	$6,497,900	$6,497,900	$6,497,900	$6,497,900	$626,000	$626,000	$626,000
($) COMMUNICATIONS	Fiber from NW to Mt. Charleston Lodge	$1,055,500	$1,055,500	$1,055,500	$1,055,500	$1,055,500	$1,055,500	$1,055,500	$1,055,500	$626,000	$626,000	$626,000
($) TRANSMISSION							$1,200,000	$1,200,000				
TOTAL COST		$82,667,400	$79,342,400	$38,189,400	$96,389,400	$38,581,400	$85,915,400	$82,116,400	$38,978,400	$21,545,000	$12,990,000	$17,480,000
LANDS - Right-of-Way Agent	[illegible]						[illegible]	[illegible]		[illegible]	[illegible]	[illegible]
ENVIRONMENTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]						
SUBSTATION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
DISTRIBUTION PLANNING & DESIGN	[illegible]	[illegible]	[illegible]		[illegible]		[illegible]	[illegible]				
COMMUNICATIONS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]				
PERMITTING RISK		MODERATE	LOW	MODERATE	HIGH	HIGH	HIGH	HIGH	HIGH	LOW/MOD	LOW/MOD	LOW/MOD
WILDFIRE IGNITION RISK		LOW	LOW	LOW/MOD	MODERATE	MODERATE	MODERATE	MODERATE	MODERATE	LOW/MOD	MODERATE	MODERATE
SITE RANKING		6	5	4	11	7	9	10	8	1	2	3

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total Score		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TESTIMONY

JESSE MURRAY

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
and Sierra Pacific Power Company d/b/a NV Energy

First Amendment to the 2023 Natural Disaster Protection Plan
Docket No. 24-12XXX

Prepared Direct Testimony of

Jesse Murray

1. Q. **PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Jesse Murray. My current position is Senior Vice President, Energy Delivery for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. **WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?**

A. I am responsible for overseeing the operations and maintenance of the electric and gas transmission and distribution systems for the Companies. I also oversee the emergency management, vegetation management, and other delivery support functions for the Companies. Finally, I oversee the strategic development and execution of the Companies' Natural Disaster Protection Plan ("NDPP") as directed by Senate Bill 329 of the Nevada Legislature and codified in NRS 704.7983. The NDPP drives the mitigation of potential wildfires and other natural disasters that could impact or be caused by NV Energy's electric facilities.

3. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I hold a Bachelor of Science degree in Chemical Engineering and a Master of Business Administration degree from the University of Nevada, Reno. I joined the Companies in 2008 as an Engineer at Frank A. Tracy Generating Station. Since that time, I have held several positions in the Companies, including Plant Engineering Manager, Maintenance Manager, Asset Management Programs Manager, and Renewable Energy Programs Director. I assumed the role of Vice President, Gas Delivery in November 2017 and assumed oversight of the NDPP in April 2021. Recently, my responsibilities expanded to include all elements of Energy Delivery in December 2024. Before joining the Companies, I worked in several engineering positions, including as a nuclear and chemical waste technical specialist. I also served as a design lead and project manager in manufacturing and commercial building construction. I am a licensed Professional Chemical Engineer in Nevada. I was also an intern with the Companies before starting my professional career. More details regarding my professional background and experience are set forth in **Exhibit Murray-Direct-1.**

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have previously testified in front of the Commission in several dockets, including most recently the NDPP Regulatory Asset Recovery Docket Nos.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

23-03004 and 24-03006 and the 2023 Natural Disaster Protection Plan filing in Docket No. 23-03003.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND WHICH WITNESSES ARE SUPPORTING THIS FIRST AMENDMENT FILING?

A. The purpose of my testimony is to provide an overview of this First Amendment to the approved Second Triennial NDPP approved in Docket No. 23-03003 for the plan years 2024 through 2026 ("First Amendment"). The First Amendment is included as **Exhibit B** to the Application. My testimony provides details regarding the key driver for this First Amendment—the need for an adjusted NDPP-related labor resource plan to execute on approved programs. This First Amendment centers around the Companies' proposal, driven by its ongoing efforts to ensure effective implementation of the NDPP, to ensure the necessary levels of internal staffing.

In addition, I provide support for the Companies' requests for certain new NDPP initiatives that incorporate new technologies and new personnel to maximize NDPP benefits. These new programs will provide identifiable benefits to customers by cost-effectively mitigating natural disaster risks.

The specific program approvals and funding requests are discussed in more detail in the direct testimonies of Danyale Howard, Alexander Hoon and Joshua Icenhower. Cary Shelton-Patchell also provides testimony on the rate impacts associated with the requests in this First Amendment (**Exhibit B** to the Application).

6. Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following Exhibits:

Exhibit Murray-Direct- 1 Statement of Qualifications

7. Q. WHY IS THE FIRST AMENDMENT NECESSARY?

A. The primary driver for the First Amendment is the need to restructure the Companies' NDPP internal labor force to better support the scope and scale of the approved 2024-2026 Plan. An assessment of ongoing NDPP implementation, driven by internal review and feedback from stakeholders and the Commission, has identified that the Companies need additional in-house labor resources to effectively execute on the NDPP. Danyale Howard's direct testimony outlines why each requested new labor resource is critically important to implement approved NDPP programs and needed to effectuate the Companies' efforts to mitigate natural disasters. The Companies propose to implement its adjusted NDPP labor resource plan using Commission-approved NDPP budget amounts.[1] So, while the adjusted NDPP labor resource plan requested in this First Amendment will not increase the Companies' total NDPP budget, NV Energy is presenting the labor resource plan here to transparently communicate the Companies' need for personnel to act on the Commission's approved scope of the NDPP. While the Commission and stakeholders have closely monitored approved NDPP personnel in prior proceedings, the Companies believe that parties' concerns regarding NDPP personnel costs should be minimized on a going forward basis as all NDPP costs transition to the general rate case recovery process provided in the updated regulations. Once implemented, the new cost recovery paradigm will

[1] My testimony below, along with more detail in the Direct Testimony of Ms. Howard, explains why the Companies have not fully expended its approved budgeted amount for 2024. Additionally, Ms. Howard's testimony, along with the First Amendment, indicates how the labor resource plan can be implemented without an increase in budgets given the level of 2024 spending and the forecasted spending for 2025 and 2026.

eliminate the potential for carrying costs associated with NDPP personnel. As a result, the adjusted NDPP labor resource plan presented in this First Amendment presents the Companies' business requirements on how to best deploy previously approved funding to executed on the 2024-2026 NDPP.

The First Amendment—specifically the adjusted labor resource plan—is the result of the Companies' continuing effort to evaluate and improve the NDPP based on implementation experience and feedback from the Commission and stakeholders. The NDPP labor resource plan adjustments will move the program toward a more stable framework to facilitate full and effective implementation of already approved NDPP programs, ensure more robust oversight for contractors, improve accountability, and streamline coordination across NDPP activities. Ms. Howard discusses the labor resource plan in detail in her testimony.

7. Q. **PLEASE PROVIDE AN OVERVIEW OF THE REMAINDER OF THE FIRST AMENDMENT REQUESTS.**

A. In addition to the adjusted NDPP labor resource plan, the First Amendment also requests additional funding for new and incremental NDPP programs and resources. These include technology investments, software, and personnel necessary to ensure that the NDPP provides adequate and cost-effective risk mitigation that leverages industrywide improvements in natural disaster protection. NV Energy is pursuing grants to potentially offset funding requests for these new investments. Ms. Howard discusses these investments in her testimony.

This First Amendment also addresses new de-energization protocols that NV Energy is implementing to reduce the risk of wildfire. These new de-energization protocols were instituted for the 2024 fire season and will be an important part of the Companies' risk mitigation strategy going forward. As part of an overall risk mitigation strategy, the Companies also are requesting limited budget adjustments for new weather stations and cameras. Mr. Hoon and Mr. Icenhower discuss the proposed modifications necessary to implement more robust risk mitigation, which include emergency de-energization, fast trip fire mode settings, and an expansion of public safety outage management ("PSOM").

The First Amendment also presents a modified plan to address the Mount Charleston area. The Commission previously approved $15.9 million for the first phase of a four-phase program to rebuild the Mount Charleston area lines to reduce fire risk and address public safety concerns. The revised proposal in this First Amendment includes costs associated with installing a permanent fire season activated microgrid. The increased costs for the microgrid in this First Amendment are relatively small compared to the costs the Companies would have incurred as an alternative, which included undergrounding lines and a new feeder tie.[2] Importantly, the microgrid configuration brings other benefits as a candidate for grant funding from the Department of Energy ("DOE"), as well as enhanced reliability and renewable energy benefits. Ms. Howard discusses the revised plan for Mount Charleston in her testimony.

[2] Companies are only seeking an additional $3.5 million in this First Amendment. Section 2.5 of the First Amendment (Exhibit B **to the Application)** shows how this $3.5 million compares to the costs the Companies were projecting to underground lines and build new feeder ties.

Finally, Ms. Howard's testimony includes a minor correction to the previously approved Tier 3 fire area maps.

I. ADJUSTED NDPP LABOR RESOURCE PLAN FOR APPROVED PROGRAMS

8. Q. WHY IS NV ENERGY PRESENTING AN ADJUSTED NDPP LABOR RESOURCE PLAN IN THIS FIRST AMENDMENT?

A. Over the past few years, the Companies have gained new insights into the organizational structure necessary to implement the NDPP. These insights are based on Companies' experience in standing up and implementing the inaugural NDPP, the scope of work approved for the Second Triennial NDPP for the plan years 2024 to 2026, as well as the information prepared for the relevant cost recovery regulatory proceedings. The Commission-directed fire agency internal audit also provided actionable feedback to help improve NDPP administration. One of the key lessons learned is that the NDPP-dedicated implementation and oversight resources did not grow commensurately to meet the demand of executing the program.

The NDPP vegetation management efforts provide an illustrative example. The Companies were able to quickly increase the contractor resources necessary to implement initial NDPP vegetation management, but oversight and administrative support for these activities should be more robust. The adjusted NDPP labor resource plan in this First Amendment includes a structural reorganization to provide more in-house resources to more effectively deploy NDPP vegetation management efforts while increasing oversight and accountability. In addition to vegetation management, the adjusted NDPP labor resource plan will provide additional in-house resources for compliance and reporting, system hardening design, system operations, troubleshooters and inspection duties, and fire season activities. Ms. Howard provides the details as to why these personnel are essential to the NDPP.

9. Q. HOW DOES NV ENERGY PLAN TO FUND THE ADJUSTED NDPP LABOR RESOURCE PLAN?

A. The Companies plan to fund the adjusted NDPP labor resource plan through the already approved 2024-2026 NDPP budgets. Ms. Howard explains in testimony that the Companies have not fully expended approved 2024 budget amounts for a number of reasons, including some efficiencies but also a heightened 2024 fire season that affected the amount of vegetation management work that could be completed. However, as explained by Ms. Howard, a predominant underlying issue across the programs is internal resource adequacy needs to effectively execute the approved scope of work. In other words, given that the requested internal labor resources are needed to fully drive implementation of approved NDPP programming, NV Energy does not need to seek any new funding to support the adjusted labor resource plan, as the new NDPP personnel positions will be funded by underspend in previously approved program costs partly driven by the needs for these resources to execute on the scope of the NDPP.[3] Because the First Amendment includes new NDPP-dedicated full-time employee positions, the Companies are requesting Commission approval prior to implementation. The 31 proposed new incremental internal NDPP personnel positions included in the adjusted NDPP labor resource plan are presented in full in **Exhibit B** to the Application.

[3] Tables 5, 6 and 7 in the First Amendment (Exhibit B **to the Application)** show that even with the additional costs from the labor resource plan, as well as the current forecast of expenses to complete approved projects through the 2026 plan year, both OMAG and capital spending for Nevada Power and Sierra remain under budget.

10. Q. DOES NV ENERGY INTEND TO REDUCE THE PLANNED NDPP SCOPE OF WORK TO FUND THE ADJUSTED LABOR RESOURCE PLAN?

A. No, to the contrary, the adjusted labor resource plan will ensure that the Companies can fully execute the approved scope of work within the Companies' control in an efficient and effective manner. As explained in Ms. Howard's testimony, the Companies' ongoing evaluation of its administration of the NDPP as part of mitigation of natural disaster risk has identified a need for in-house people resources to facilitate logistical coordination, oversight and quality assurance, particularly to oversee the NDPP's contract workforce.

II. INCREMENTAL NDPP PROGRAMS

11. Q. WHY ARE THE COMPANIES REQUESTING NEW PROGRAMS IN THIS FIRST AMENDMENT?

A. The Companies are requesting new programs in this First Amendment to ensure the NDPP continues to address emerging natural disaster risk with appropriate resources. These new programs include both new software and new NDPP-dedicated personnel to implement new programs. As utilities around the west—and the country—continue to adapt to extreme weather and fire threats, the technologies and resources necessary to implement risk mitigation also adapt. The new technologies NV Energy is requesting to implement in this filing include AiDash and Palantir Foundry. These technologies will leverage advanced algorithms to inform and efficiently leverage the Companies' resources and to harmonize the NDPP with Expert Working Group partners.

NV Energy is also requesting approval for new positions for NDPP-dedicated distribution automation and hazard awareness desk operators. These new positions will help NV Energy ensure that the distribution system can be operated safely to prevent and mitigate wildfires while also providing safe and reliable service to customers. As explained in the Prepared Direct Testimony of Mr. Icenhower, some of the NDPP's grid resilience operating practices, such as the fire season protocols, can impact reliability, but distribution automation helps to reduce or shorten outages caused by these NDPP-related activities.

12. Q. ARE THESE NEW PROGRAMS INCREMENTAL TO THE COMPANIES' NORMAL COURSE OF BUSINESS?

A. Yes, these new programs are incremental to the normal course of business and are necessary to effectively implement the NDPP. The new AiDash technology, proposed as an 18-month pilot program in this First Amendment, is specifically designed to advance current NDPP-related vegetation management efforts with enhanced data gathering and predictive analysis, supporting the allocation of resources and prioritization of projects. Palantir Foundry is incremental in that it systematically collects, curates, transfers, and analyzes larger, interrelated, and dynamic wildfire-related datasets for reporting, internal and external communications, work tracking and other workflows using dashboards and event management capabilities. The Companies do not currently have either technology or capability, but require these technologies to more effectively implement the NDPP.

Similarly, the hazard awareness warning desk will provide an NDPP-dedicated resource in NV Energy's grid operations center. This desk will monitor wildfire and other natural disaster risk 24 hours a day and 365 days a year and work with system operations to assess impacts of natural disasters on grid operations and supply real-time outage assessments to minimize impacts to customers while reducing risk. These are services NV Energy currently lacks.

The distribution automation function would refresh outmoded protection on distribution circuits, many of which have not been comprehensively reviewed or updated for 20 to 30 years. Performing coordination studies on higher risk distribution circuits anticipate a reduction in fault clearing times to lower wildfire risk, improve safety, and significantly improve reliability—reliability that may be detrimentally impacted by other NDPP programs that improve resilience but ultimately cause more system outages to mitigate wildfire risk. Specifically, the new distribution automation team will perform engineering studies and system analysis to assess the impact of potential de-energization—whether from PSOM, emergency de-energization or fast trip fire mode—and identify how system outages can be smaller in scope or shorter in duration. Distribution automation experts also will proactively perform in-depth analysis to address potential miscoordinations on the distribution network, which could inadvertently create wildfire hazards. They will also evaluate industry advancements for additional mitigation opportunities through automation schemes, such as falling conductor detection and sensor technologies that may reduce the chance of igniting wildfires. These advancements also make the system more robust against other severe natural disasters, like heavy snowstorms with wet snow taking down sections of distribution network.

13. Q. PLEASE EXPLAIN THE GRANT FUNDING OPPORTUNITIES FOR THESE NEW RESOURCES.

A. The Companies have actively pursued DOE Grid Resilience and Innovation Partnerships ("GRIP") funding for new programs and technologies to help offset costs. Recently, the DOE announced that NV Energy was successfully selected as part of a consortium entering into negotiations for funding from the GRIP program. If negotiations are successful, NV Energy expects the GRIP grants will offset some costs of the new programs requested in this First Amendment.

14. Q. WHAT IS THE TOTAL BUDGETARY IMPACT OF THIS FIRST AMENDMENT FILING?

A. The total budgetary impact of this First Amendment is an $6,316,529 increase in Operations, Maintenance, Administrative, and General ("OMAG") expenditures through the end of the Plan (2026), which includes a $8,516,931 increase for Sierra and $2,200,401 decrease for Nevada Power. The First Amendment also results in an additional $1,902,535 in capital expenditures through the end of the Plan, with a proposed $1,643,594 decrease in capital expenditures for Sierra and a $3,546,129 increase for Nevada Power for the 2024-2026 Plan years.

The Prepared Direct Testimony of Ms. Howard and Application **Exhibit B**, which is the 2024 NDPP First Amendment, provides a more detailed breakdown of the total funding requests.

15. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications
for
JESSE E. MURRAY, P.E.

Summary of Qualifications

20 plus years of engineering and utility leadership experience. Broad experience in process design, utility operations, problem analysis, project management, business operations, risk analysis, and financial analysis. Extensive knowledge in energy market fundamentals, combustion and steam turbines, contract negotiation/administration, and commercial construction techniques.

Professional Experience

Senior Vice President, Energy Delivery
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
February 2022 – Present

Responsible for overseeing the operations and maintenance of the electric and gas transmission and distribution systems for the Companies. Also includes the emergency management, vegetation management, and other delivery support functions for the Companies. Also responsible for executing the Natural Disaster Protection Plan as required by SB 329 of the 2019 Nevada Legislature and NRS 704.7983.

Vice President, Electric Delivery and Natural Disaster Protection
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
February 2022 – Present

Responsible for overseeing lines operations and maintenance, meter operations, operations support, emergency management, and vegetation management activities for NV Energy's electric transmission and distribution assets. Also responsible for executing the Natural Disaster Protection Plan as required by SB 329 of the 2019 Nevada Legislature and NRS 704.7983.

Vice President, Gas Delivery and Natural Disaster Protection
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
November 2017 – February 2022

Responsible for overseeing the operations, engineering, construction, compliance, service, and financial activities of NV Energy's gas distribution utility. Responsible for executing the Natural Disaster Protection plan as required by SB 329 of the 2019 Nevada Legislature and NRS 704.7983. The plan addresses and mitigates wildfire and other natural disaster risks that could impact or be caused by electric facilities in high risk areas (natural disaster protection added April 2021).

Director, Renewable Energy Programs
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
March 2015 - November 2017

Responsible for the implementation of several behind the meter customer renewable generation programs as required by NRS 701B. This included overseeing the development of the annual plan, management of the customer incentive process, interfacing with community stakeholders, and ensuring compliance with regulations.

Manager, Maintenance
Sierra Pacific Power Company d/b/a NV Energy
March 2014 – March 2015

Responsible for leading the engineering and maintenance organization at Frank A. Tracy and Fort Churchill generating stations. Managed a staff that provided plant maintenance and engineering support, equipment performance testing, and execution of plant betterment projects. Responsible for developing and executing long term business plans, including capital and O&M budgeting, workforce design, and major maintenance scheduling.

Manager, Asset Management Programs, Power Generation
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
June 2013 – March 2014

Responsible for designing and implementing an Asset Management Program for NV Energy's 6,000MW natural gas and coal fired generation fleet. Responsible for all aspects of the program, including strategic planning, financial justification, quantitative risk assessment, resource prioritization, outage scheduling, and alliance contracting.

Manager, Plant Engineering and Technical Services
Sierra Pacific Power Company d/b/a NV Energy
August 2011 – June 2013

Responsible for leading the engineering and maintenance organization at Frank A. Tracy and Fort Churchill generating stations. Managed a staff that provided engineering support, equipment performance testing, and execution of plant betterment projects. Responsible for developing and executing long term business plans, including capital and O&M budgeting, and major maintenance scheduling.

Staff Engineer
Sierra Pacific Power Company d/b/a NV Energy
January 2008 – August 2011

Provided plant engineering services at Frank A. Tracy and Fort Churchill Generating Stations. Included a focus on process design, water treatment, major maintenance, and plant betterment.

Engineer III
International Game Technology
October 2003 - January 2008

Responsible for managing major construction and space planning projects. Directed major real estate transactions on commercial buildings and undeveloped land. Managed major capital improvement projects throughout the project life cycle. Conducted property searches for new offices in developing markets, and negotiated the lease terms for these new properties. Managed existing leases at 40 locations in North America.

Associate Engineer
Bechtel BWXT Idaho – Idaho National Engineering Laboratory
June 2002 - October 2003

Characterized and managed chemically hazardous radioactive waste as prescribed by the Resource Conservation and Recovery Act (RCRA). Initiated and coordinated commercial disposition shipments to reduce nuclear and hazardous waste inventory within the State of Idaho.

Education

Master of Business Administration, University of Nevada, Reno, December 2007

Bachelor of Science with High Distinction in Chemical Engineering, University of Nevada Reno, June 2002

State of Nevada Professional Engineering License 21314, Chemical Engineering

Appearances in front of the Public Utilities Commission of Nevada

- 15-07041/2 Net Metering Cost of Service Docket
- 16-02006 Renewable Generations Annual Plan
- 16-03003 Nevada Power Annual Deferred Energy Accounting Adjustment
- 16-03004 Sierra Pacific Power Annual Deferred Energy Accounting Adjustment
- 16-03005 Sierra Pacific Gas Annual Deferred Energy Accounting Adjustment
- 16-07001 Sierra Pacific Power Company Triennial Integrated Resource Plan
- 16-08027 Nevada Power Second Amendment to the Triennial Integrated Resource Plan
- 17-02007 Renewable Generations Annual Plan
- 17-03001 Nevada Power Annual Deferred Energy Accounting Adjustment
- 17-03002 Sierra Pacific Power Annual Deferred Energy Accounting Adjustment
- 17-03003 Sierra Pacific Gas Annual Deferred Energy Accounting Adjustment
- 21-03004 Natural Disaster Protection Plan 2020 Regulatory Asset Recovery
- 22-03006 Natural Disaster Protection Plan 2021 Regulatory Asset Recovery
- 22-08001 2nd Amendment to the 2020-2023 Natural Disaster Protection Plan
- 23-03003 2024-2026 Natural Disaster Protection Plan
- 23-03004 Natural Disaster Protection Plan 2022 Regulatory Asset Recovery
- 24-03006 Natural Disaster Protection Plan 2023 Regulatory Asset Recovery

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JESSE MURRAY, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: December 17, 2024

Jesse Murray
JESSE MURRAY

DANYALE HOWARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
and Sierra Pacific Power Company d/b/a NV Energy

First Amendment to the 2023 Natural Disaster Protection Plan
Docket No. 24-12XXX

Prepared Direct Testimony of

Danyale Howard

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Danyale Howard. My current position is Director, Natural Disaster Protection for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. I am responsible for the implementation of the Companies' Natural Disaster Protection Plan ("NDPP") pursuant to NRS 704.7983. The NDPP drives the mitigation of potential wildfires and other natural disasters that could impact or be caused by the Companies' electric facilities.[1]

[1] NRS 704.7983(2).

3. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have 28 years of experience in the utility industry. Before assuming my current role, I held the role of Director, Distribution Design Services, responsible for electric and gas design and project management of distribution line extensions subject to the Rule 9 Line Extension tariffs, local governmental franchise agreements, and electric distribution reliability projects for Northern Nevada. In June 2021, I assumed the role of Director, Natural Disaster Protection, responsible for system hardening, grid ruggedization, and the circuit patrols and detailed inspection programs. In October 2023, I assumed the NDPP operations and compliance responsibilities, consisting of emergency management, situational awareness, vegetation management, and fire season operations protocols. My statement of qualifications is attached as **Exhibit Howard-Direct-1.**

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have submitted testimony and appeared before the Commission multiple times, most recently in the Cost Recovery for the 2023 NDPP Regulatory Asset Account, Docket No. 24-03006.

5. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following Exhibits:

Exhibit-Howard-Direct-1, Statement of Qualifications

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Portions of **Exhibit B** to the Application, which is the Companies' First Amendment to the Second Triennial NDPP for plan years 2024-2026 ("First Amendment")

- Section 2.1 Labor Resource Plan for Approved Programs
- Section 2.2 Enhanced Fire Season Protocols
- Section 2.4 Resource and Technology Plan to Implement New Programs
- Section 2.5 Mount Charleston Rebuild
- Section 2.6 Grand Funding Negotiations
- Section 2.7 Mapping Corrections

6. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the scope and need for the resources requested in this First Amendment to the NDPP approved in Docket No. 23-03003 for plan years 2024 to 2026 ("Plan"). Specifically, I address the following:

1. Based on an assessment of ongoing NDPP implementation, driven by internal review and feedback from stakeholders and the Commission, the Companies are requesting an adjusted NDPP labor resource plan that will hire in-house labor to help implement the currently approved NDPP scope of work. The NDPP scope has not changed significantly since the inaugural plan; however, as the initiatives transitioned from conceptual plans to real-world work assignments, the need for people resources to facilitate logistical coordination and quality assurance has grown. My testimony explains in detail why additional in-house labor resources are absolutely required to accomplish the natural disaster risk mitigation approved by the Commission via implementation of the Second Triennial

NDPP. I also explain below why this labor resource plan can be funded through approved budget amounts, as the Companies did not expend 2024 approved amounts, partly as a result of the need for these in-house labor resources to drive implementation of currently approved programs.

2. The Companies' request for Commission confirmation of its enhanced fire season protocols as part of NDPP-approved programming. De-energization, along with other enhanced fire season protocols, were implemented in the 2024 fire season to ensure safe and reliable service. As part of implementation of these enhanced fire season protocols, the Companies also seek to add fire cameras and weather stations to improve situational awareness. Witnesses Alexander Hoon and Josh Icenhower also support the new protocols.
3. NV Energy's request for new NDPP programs and technologies that are incremental to the Companies' normal course of business and will support the NDPP program. These programs include a dedicated hazard awareness desk and a distribution automation team prioritized for fire mitigation.
4. Nevada Power's request to modify the previously approved Phase 1 Mount Charleston rebuild to include a microgrid.
5. The Companies' request for minor corrections to the Tier 2 Lake Tahoe and Tier 1 Mount Charleston maps.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

I. NDPP ADJUSTED LABOR RESOURCE PLAN

7. Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE ADJUSTED LABOR RESOURCE PLAN PRESENTED FOR APPROVAL IN THIS FIRST AMENDMENT.

A. This First Amendment presents an adjusted labor resource plan to effectively implement approved NDPP activities and programs. While the NDPP approved programs have not changed significantly, the passage of time and lessons learned given challenges to implementing the currently approved programs, as well as feedback on administration of the NDPP from the Commission and stakeholders, has demonstrated that the Companies require additional internal resources to support the currently approved scope of work. The requested resources are necessary to develop the NDPP into a more mature program with sufficient compliance and organizational efficiency. In particular, the Companies have identified that more effective administration is needed for the existing contracted-for resources to execute on NDPP activities.

The specific positions, totaling 31 new full time employees, are shown in Table 4 of the First Amendment (**Exhibit B** to the Application).

8. Q. HOW DOES THIS REQUESTED LABOR RESOURCE PLAN AFFECT CURRENTLY APPROVED BUDGETS?

A. As discussed in more detail below, the Companies have not fully expended approved 2024 budget amounts for a number of reasons. However, a predominant underlying issue across the programs is internal resource adequacy needs to effectively execute the approved scope of work. Given that the requested internal labor resources are needed to fully drive implementation of approved NDPP programming, and without those resources there was reduced spending in 2024, those budgeted amounts can be carried over to 2025 and 2026 to support the labor resource plan requested in this First Amendment. Ultimately, the new in-house resources, which the Companies intend to manage from a budgetary perspective within the currently approved amounts, will aid in achieving the risk mitigation the Commission approved in the Second Triennial NDPP for plan years 2024 to 2026.

9. Q. FROM A HIGH-LEVEL PERSPECTIVE, WHY DO THE COMPANIES REQUIRE ADDITIONAL LABOR RESOURCES TO EXECUTE ON APPROVED PROGRAMS?

A. Additional internal NDPP personnel are required to execute the approved scope of work, operate the system reliably and efficiently, administer additional anticipated grant funding, and continue to reduce risks from natural disasters. The proposed positions will be focused on day-to-day execution of NDPP projects and programs, ensuring support is available to meet NDPP milestones, statutory requirements (NRS 704.7983), regulations implementing statutory requirements and Commission orders. These positions ensure NDPP functions can be addressed as a non-discretionary initiative. Supplementing the existing internal workforce to improve NDPP administration and implementation enables the Companies to provide necessary oversight on projects and meet the NDPP workload that exists today, as well as on NDPP projects that will extend well beyond the Companies' ten-year business plans.

10. Q. WHY DID NV ENERGY IDENTIFY THE NEED FOR THESE POSITIONS AT THIS POINT IN TIME?

A. During 2023 and 2024, the Companies assessed the NDPP implementation, incorporated stakeholder feedback, and reviewed the fire agency internal audit to determine how best to mature the program. This review indicated a need for additional internal resources to execute on NDPP programs, align utility fire mitigation and response practices, and improve compliance and administration of NDPP initiatives. The Companies also identified a critical need for additional NDPP personnel to improve policy formalization, procedure documentation, reporting, and training. The NDPP labor resource plan presented in this First Amendment supports these efforts guided by the regulatory requirement to have "an adequately sized and trained workforce to execute the natural disaster protection plan."[2]

[2] LCB File No. R085-19, Sec. 7(2)(k).

As noted above, the NDPP scope has not changed significantly since the inaugural plan, but implementation challenges and lessons learned has demonstrated the need for people resources to facilitate logistical coordination and quality assurance has grown. In particular, the NDPP-dedicated contract workforce grew, with the greatest increase in contract workforce occurring 2022 and 2023. Table 3 in the First Amendment (**Exhibit B** to the Application) shows the average annual NDPP contract workforce utilized during 2023 and 2024. Based on the scope and scale of the work approved in the 2023 NDPP for plan years 2024-2026, the Companies estimate the total average workforce required to implement the Plan – including contractors – is more than 500 full time equivalents ("FTEs").

The NDPP personnel count has not kept pace with the growth of the contract workforce needed to meet the scope of work. From 2022 through 2024, the NDPP core team managed workforce levels equal to or greater than many existing regular business units. As a result, the NDPP does not have appropriate front-line leadership with direct oversight of the various NDPP programs and contractors to manage these workers. As a comparison, during peak season, the NDPP uses the same number of electric lines construction crews as all Northern Nevada - Electric Delivery internal lines construction crews combined but has significantly less internal resources to provide leadership and oversight over this work. As another example, the Companies increased vegetation management field actions tenfold since 2019, while internal resources only doubled during the same period.

11. Q. PLEASE ADDRESS THE SHORTFALLS THE LABOR RESOURCE PLAN IS MEANT TO RESOLVE.

A. It has become apparent that an NDPP personnel shortfall exists in both oversight positions and the unique positions required to coordinate NDPP program execution logistics. For example, needs exist for administration, documentation and training. Because the NDPP relies heavily on contract resources, the internal workforce must establish fluency of subject matter knowledge to standardize processes and oversight, as well as to engage in contract administration, invoice review, remittance processing, and overall quality assurance. Contract resources also require onboarding, training, and ongoing administration. Furthermore, the NDPP's multiple long-term programs of varying size and complexity require significant people and equipment resources to initiate, execute, and maintain the programs effectively. In summary, the labor resource plan is meant to ensure a capable and qualified core team to develop, document, and execute the programs, ensuring a high quality of work output from both internal and external sources.

12. Q. HOW DOES THE NDPP LABOR RESOURCE PLAN ADDRESS THESE GAPS?

A. The adjusted NDPP labor resource plan is one part of an overall reorganization of the NDPP core team. The NDPP reorganization aims to establish a manageable span of control[3] by adding front-line leadership to oversee the contractor and internal workforce, organized by sub-groups based on specialized functions. Until recently, nearly all NDPP functions flowed directly from the front-line workforce to the Director without any intervening

[3] Span of control refers to the number of subordinates a manager or superior can effectively oversee. Span of control influences efficient organizational operations targeting adequate workload and employee oversight. For NDPP, subordinates include employees and contractors.

management. This is an extremely wide span of control when considering a workforce of ~500 contract personnel performing a high volume of diverse work types that adhere to varying contract terms and scopes of work, contractual transactions, and financial and budget oversight. This wide span of control across differing work types also strains the Companies' ability to develop policies and procedures for consistent direction and adoption of new best practices. The Companies plan to implement front-line leadership to provide direct supervision, signature authority and accountability for specific work types. Front-line leaders will be directed by the NDPP Director charged with developing global direction for the NDPP program, including overall oversite and management of program execution.

Figure 1 in the First Amendment (**Exhibit B** to the Application) shows how the labor resource plan will insert front-line leadership to oversee internal and contract resources to: (1) administer programs/processes; (2) formalize procedures and training that achieve the baseline fluency and ensure accountability of high-quality deliverables; and (3) keep pace with evolving utility best practices for risk mitigation.

13. Q. HOW WILL THE COMPANIES IMPLEMENT THE ADJUSTED NDPP LABOR RESOURCE PLAN?

A. The adjusted labor resource plan includes 31 internal positions that will reside within the NDPP core team. The Companies assessed the oversite and execution of each NDPP initiative, identified gaps and developed a four-phase developmental action plan that includes onboarding employees in three phases based on a sequential developmental tract that parallels ongoing deliverables to the NDPP and critical preparedness to meet seasonal events such construction and fire season. Those positions are identified in Table 4 of the First Amendment (**Exhibit B** to the Application), and I detail why each of these positions are needed below. Additional detail regarding each position's function is provided in the First Amendment.

The Companies will carefully integrate these new positions in managed phases that coincide with continued implementation of seasonal NDPP deliverables, while also ensuring responsiveness to fire season events. These phases are outlined in the First Amendment (**Exhibit B** to the Application).

14. Q. PLEASE EXPLAIN THE NEED FOR A SENIOR OPERATIONS ANALYST POSITION IN THIS FIRST AMENDMENT.

A. The new Senior Operations Analyst position is needed to identify processes to capture and consolidate data for the NDPPs multiple programs performance to analyze, and coordinate requirements related to the NDPP's legislative, regulatory, and other compliance areas. This position would also support process efficiencies and documentation for the various NDPP programs. Today, NDPP programs are tracked in disparate systems that complicate progress tracking for stakeholders, the Commission, and for internal purposes. Currently, the Companies' personnel and contractors prepare this information on an ad hoc basis without a centralized point of contact. As the NDPP and its programs mature, progress tracking and reconciliation become increasingly important to create efficiencies and minimize chances for error. This position provides benefits to customers by providing improved access to data, the access to standardized reports, and the ability to create dashboards on NDPP activities. Doing so enhances the Companies' ability to monitor and identify trends or more minor issues prior to becoming more significant concerns.

15. Q. PLEASE EXPLAIN THE NEED FOR DISTRIBUTION DESIGN POSITIONS REQUESTED IN THIS FIRST AMENDMENT.

A. Based on the significant hardening and ruggedization objectives, utility design administrators ("UDAs"), a utility design coordinator, a standards engineer, and a General Foreman are required. Ruggedization programs take significant effort to implement, and these resources are incremental to the new business and regular business that NV Energy conducts. Based on approved budgets for construction milestones and the estimated design and permitting approved for 2025 and 2026, NV Energy will need to design approximately $100 million in NDPP distribution projects each year to meet NDPP system hardening and grid ruggedization milestones on a going forward basis.

The NDPP's current small design team is challenged to maintain pace with the scheduled projects, which could result in some projects being launched without full review. In other cases, project designs drafted by general business unit UDAs without specific fire mitigation design experience can cause errors resulting in further delays for NDPP projects. Ideally, NDPP designs should be scoped and completed one to two years before construction to accommodate permitting, material lead times and construction resource alignment. This timing supports the development of predictable cashflow forecasts. Not having advanced design estimates contributes to supply chain issues.

Currently, Northern Nevada NDPP system hardening design is performed by one NDPP-dedicated UDA, two contract designers, and some contract engineering. In Southern Nevada, one NDPP contract designer is assigned to NDPP system hardening design. Additionally, NDPP work is reviewed by various internal regional engineers on an ad hoc basis depending on availability. As a comparison, the Northern Nevada Distribution Design Service unit – a regular business unit within NV Energy – has 28 UDAs with approximately 29 support positions, but the quantity of distribution they design (in dollars) for new business in Northern Nevada is less than the amount required for NDPP. The normal business unit UDAs also do not have the skill set or training to design NDPP projects and are fully dedicated to existing or new business outside the NDPP.

Hiring new NDPP UDAs is necessary to develop fluency in fire mitigation design, streamline the design process and accomplish the NDPP work. The additional UDAs will address the shortfall in resources, will ensure that the NDPP team can meet system hardening milestones, and will establish procedures, standards, and training that the Companies can leverage going forward.

The utility design coordinator and standards engineer are needed to oversee NDPP design work, both internally and externally. The standards engineer also is needed as a resource to develop certain standardization for the NDPP program and will be working with peer utilities on emerging technologies and protocols. The need for the General Foreman aligns with the need for the UDAs, utility design coordinator and standards engineer, because the General Foreman is needed to improve consistency for design review, as well as to liaison with other electric lines business units and third-party contractors to reinforce NDPP standards and develop inspection criteria for final work validation of system hardening fire mitigation construction methods performed by third-party contractors. Without all these positions, the NDPP is at risk of having inadequate designs and could experience continued delays meeting risk mitigation milestones.

16. Q. PLEASE EXPLAIN THE NEED FOR THE PROCUREMENT ANALYST POSITION REQUESTED IN THIS FIRST AMENDMENT.

A. The proposed procurement analyst position will coordinate the many facets of contract administration to support logistics to meet seasonal work schedules and ensure that those elements are performed according to established policy and control measures. Most of the NDPP work is conducted through contracts, and a procurement analyst would help coordinate those contract resources, allowing NDPP project managers to focus on managing project milestones. Currently, this role is spread across various project managers having varying experience. Establishing this position centralizes the procurement process and allows the analyst to become a subject matter expert fluent in the Companies' procurement procedures and controls. Without this position, NDPP projects will be subject to delay and inconsistency because project managers are not adequately supported to perform the ancillary contract administration as well as logistical coordination of managing multiple projects and programs. Customers will benefit through the safeguarding and expertise the procurement analyst adds to the contract process and subsequent effort that allows project managers to focus narrowly on management of project coordination to meet NDPP risk reduction milestones.

17. Q. PLEASE EXPLAIN THE NEED FOR THE ELECTRIC LINES TROUBLESHOOTER AND ELECTRIC INSPECTOR POSITIONS REQUESTED IN THIS FIRST AMENDMENT.

A. The electric lines inspections positions consist of five troubleshooters and two inspectors. In the field, NDPP troubleshooters and inspectors are needed to collaborate with the system operators to optimize coordination of planned outages to minimize customer disruptions. Third-party contractors cannot perform switching or make line clearances on NV Energy equipment. These lines personnel will perform critical work validation and conduct the final quality assurance/quality control ("QA/QC") inspection for adherence to the Companies' fire mitigation standards.

The NDPP currently employs approximately 14-19 third-party line crews for system hardening and grid ruggedization work during peak construction season, but as the Companies complete NDPP system hardening design for other Tier areas beyond Tier 3, line construction resource needs will increase and will be deployed year-round instead of seasonally. For comparison, the Northern Nevada electric operations subject to the normal course of business currently have approximately 16 internal line crews in addition to a few contract crews, but the level of work they do is roughly equivalent to or less than what will be required for NDPP in the future.

Without sufficient troubleshooters and inspectors to prioritize the NDPP work, the NDPP team has not had resources necessary to conduct the approved scope of work, and switching location confusion and inconsistent application of fire mitigation standards has occurred. These issues can result in change orders from mobilized contractors, missed schedules, and inaccurate information being provided to residential and commercial customers. An additional potential result is cancelation of planned outages that were previously communicated to customers, thereby impeding customers' ability to plan accordingly.

18. Q. PLEASE EXPLAIN THE NEED FOR THE SYSTEM OPERATIONS POSITIONS REQUESTED IN THIS FIRST AMENDMENT.

NV Energy is requesting five new NDPP system operations positions. These resources are required to coordinate the necessary outages that are incremental and more specialized as compared to normal course of business work. Because NDPP projects are numerous and occur in small geographic areas, they require complex switching coordination to optimize progress while minimizing customer outage impacts. Thus, the NDPP system operations will coordinate NDPP project outage to support the limited NDPP work windows, as well as incorporate natural disaster related situational awareness information into the operations protocols.

Normal course of business system operations personnel currently assists with these activities, but are already fully allocated to non-NDPP business, including other emergency calls and unplanned outages. As such, a lack of NDPP-related system operations coordination has resulted in the Companies' system control being overloaded and unable to satisfy previously approved switching and outage requests. Without these NDPP system operator positions, NDPP outages cannot be prioritized and planned to avoid cancellation. Canceled outages ultimately cause a chain reaction that results in missed milestones, resulting in avoidable risks on the Companies' system. Customer benefits associated with these system operator positions include more steady progress on NDPP risk reduction initiatives.

19. Q. PLEASE EXPLAIN THE NEED FOR THE VEGETATION MANAGEMENT POSITIONS REQUESTED IN THIS FIRST AMENDMENT.

A. Various professionally qualified resources are needed to support the traditional aerial clearance and hazardous ground fuels management programs. Past regulatory asset hearings, internal audits, and the Companies' assessments have revealed significant areas for improvement in field and administrative oversight for vegetation management. These positions will improve NDPP vegetation management efforts by better aligning resources, providing clear progress reporting, ensuring invoicing matches contracts, and identifying potential gaps in obligations related to stewardship agreements and grants.

The Vegetation Management Administrators ("VMAs") are needed to oversee contractors in performing vegetation management work. In this role, the VMAs will replace the activities previously conducted by the Fire Mitigation Specialist and Fire Mitigation Officer ("FMO"), which will allow FMOs to focus on other activities better suited to their skill set and expertise, as explained more in Q&A 21. The NDPP vegetation management senior project manager will help the Companies refine estimates and schedules for vegetation management, ensuring levelized costs and coordinated schedules going forward.

The business coordinator is needed to ensure quality assurance in the invoice review process. NDPP vegetation management invoice volumes are substantial and additional administrative support is necessary to ensure proper review. Today, a combination of internal employees partnered with third-party administrator contractors perform these invoice reviews. The NDPP has added five people to facilitate the new invoice process, but a coordinator is required. The volume of invoices combined with the new invoice process has resulted in a loss of efficiency, jeopardizing timely payment to suppliers, which can be resolved with the aid of a business coordinator.

20. Q. PLEASE EXPLAIN THE NEED FOR THE FIRE MITIGATION AND EMERGENCY MANAGEMENT POSITIONS REQUESTED IN THIS FIRST AMENDMENT.

NV Energy is requesting to hire a new Manager of Fire Mitigation, an FMO, and a Senior Emergency Manager Administrator. As part of the position realignment, the Companies' request to add one new FMO, resulting in four total FMOs statewide (one for the Northeast region, two for the Reno/Sparks/Carson area and one for Southern Nevada).

FMOs will have a more fire specialized role going forward and will be phased out of direct control over vegetation management. The FMOs are necessary for more accurate fire incident analysis, tracking and reporting, as well as for internal training and external coordination. The FMOs will serve a key function within the NDPP's Incident Command System as the emergency operations response liaison to public safety agencies for natural disaster related events specifically public agency incident command centers and commanders to provide the Companies with real-time information. The new training conducted by the FMOs aims to promote a "one mission" culture that extends beyond the NDPP core group and begins to normalize fire mitigation efforts within general business units using a change management approach. Placing FMOs in a position to consult, liaise, analyze, and train capitalizes on their fire response operational expertise for improved efficiencies. It serves a dual purpose of educating the utility and public safety partners about fire and the utility's specialized needs. The changes for FMOs also aim to achieve appropriate balance for the fire agency partnerships, to fully focus on fire response and to reassign the financial and contractual gains of work assignments.

The Manager of Fire Mitigation and Senior Emergency Manager ("EM") Administrator are needed to oversee various wildland operational practices, prevention measures including internal and external stakeholder training and exercises. Fire Mitigation Officers in particular, are a key decision maker for emergency de-energization and determining credible intelligence based on their expertise and through their liaison with cooperators and other external public safety agencies. The lack of these resources has resulted in gaps in administration and training. In summary, the requested positions are necessary to support emergency preparedness and the company's operations when performed during heightened fire risk conditions, including coordination with public safety partners, the Expert Working Group ("EWG"), and other agencies.

21. Q. WHAT IS THE TOTAL COST IMPACT FOR THE ADJUSTED LABOR RESOURCE PLAN?

A. The Companies understand the need to manage within its existing approved budgets. As such, utilization of 2024 budgeted amounts that were not expended, carried over to 2025 and 2026, can provide the funding needed for the adjusted labor resource plan. Tables 5, 6 and 7 in the First Amendment (**Exhibit B** to the Application) show that even with the additional costs from the labor resource plan, as well as the current forecast of expenses to complete approved projects through the 2026 plan year, both OMAG and capital spending for Nevada Power and Sierra remain under budget. In other words, the adjusted labor resource plan cost in combination with the currently forecasted budget changes results in a cumulative savings when compared to the currently approved budgets.

22. Q. WHY ARE THE FORECASTED 2024-2026 NDPP EXPENDITURES FOR EXISTING PROGRAMS BELOW THE APPROVED BUDGET AMOUNTS EVEN WITH THE ADJUSTED LABOR RESOURCE PLAN?

A. The 2024 approved amounts were not reached for a variety of reasons. For example, NDPP capital and OMAG expenses are delayed given implementation challenges resulting from some transitions that have occurred with the Plan. For example, Sierra had reduced capital spending in 2024 partly because of undergrounding and substation improvement delays. Also, the transition to the new fire agency contracting structure and the lead-time to

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complete a Request for Proposals ("RFP") for third-party contracts has complicated scheduled vegetation management activities. Importantly, a heightened fire season also limited the scope of vegetation management work in 2024 that contributed to reduced OMAG expenses. The reduced OMAG expenditures is also due to efficiencies gained in some programs such as circuits patrols and detailed inspections and resolving resulting corrections. These efficiencies have contributed to lower costs.

However, a predominant underlying issue across the programs is internal resource adequacy to effectively execute the approved scope of work, which is why the Companies are proposing a full suite of new internal labor resources. While the Companies have instituted process improvements throughout the NDPP, these improvements do not address the workforce strain related to NDPP implementation. Put simply, the Companies' existing workforce is insufficient to support the NDPP activities on a consistent basis. Without internal labor resources prioritized for NDPP activities, NDPP execution will continue to suffer from inconsistencies that result from the current labor configuration.

23. Q. HOW DOES THE ADJUSTED LABOR RESOURCE PLAN BENEFIT CUSTOMERS?

A. Implementing the NDPP requires transformational change at the Companies, as implementing effective natural disaster prevention in the face of more extreme weather has proven to be significant in both scale and scope. Also, implementing the NDPP's multiple programs requires long-term planning and execution, which mandates major shifts in strategy at the Companies to provide the safe and reliable service well into the future. The adjusted labor resource plan is the next step of this transformational process and establishes formal leadership over related initiatives and improves the structure and quality assurance controls to ensure implementation of risk mitigation measures are performed timely and at a reasonable cost.

ENHANCED FIRE SEASON PROTOCOLS

24. Q. WHAT ENHANCED FIRE SEASON PROTOCOLS ARE AT ISSUE IN THE FIRST AMENDMENT FILING?

A. The Companies describe three specific modifications to the existing fire season protocols below. These enhanced fire season protocols were implemented for the 2024 fire season without any 2024 NDPP budgetary impact as detailed in the Companies' July 3, 2024, NDPP Progress Report, Informational Update ("Informational Update") in Docket No. 24-07003. The Companies intend to keep these protocols in place going forward and now seek Commission confirmation of the protocols as part of the approved NDPP.

Expanded Public Safety Outage Management ("PSOM"): Expanding PSOM to the entire service territories for the Companies to prevent powerline-initiated wildfires during high-risk conditions wherever those conditions arise.

Fast Trip Fire Mode ("FTFM"): Providing an automatic, rapid response to electrical faults, reducing the likelihood of powerline-caused wildfires.

Emergency De-Energization: A safety measure when there is an imminent threat from an existing wildfire. Emergency de-energization serves as an additional layer of protection.

Mr. Hoon and Mr. Icenhower provide detailed testimony supporting these enhanced fire season protocols and explain their proposed implementation. Mr. Hoon specifically provides details regarding the need for the situational awareness enhancement investments and how the Companies' requested combined initiatives work together to mitigate wildfire risks, improve grid resilience, and enhance public safety.

25. Q. WHY DID THE COMPANIES IMPLEMENT THE ENHANCED FIRE SEASON PROTOCOLS FOR THE 2024 FIRE SEASON?

A. The 2024 fire season was forecasted to be of heightened risk, so the Companies proactively took steps to expand the enhanced fire season protocols. NV Energy's 2024 post-season assessment confirms that actual fire events were elevated compared to prior years, validating the early 2024 forecast. As of November 22, 2024, the Nevada has experienced the following:

- 862 fires and 66,520[4] acres burned, an increase from 66 fires and 7,784 acres burned in 2023.[5]
- 207 fire incidents requiring NV Energy assessment or response, an increase from 43 total fire incidents in 2023.
- 40 Red Flag Warnings, an increase from 12 total in 2023. Red Flag Warnings prohibit planned work in high-risk areas.[6]
- The Companies activated seven emergency de-energization events and five PSOMs year to date 2024, compared to one PSOM event in 2023. All activations were reported to the Commission using the regular reporting process.

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[4] https://gacc.nifc.gov/gbcc/predictive/products/gbytd-byState.htm. Nevada fire counts recorded include fires on federal land or supported by federal funding, these counts do not include all non-federal fires.
[5] https://gacc.nifc.gov/gbcc/predictive/intelligence/historical-ytd-stats/2023/2023_GB_RxbyState.htm.
[6] National Weather Service, Iowa Environmental Mesonet

26. Q. PLEASE DISCUSS STAKEHOLDER ENGAGEMENT RELATED TO THE ENHANCED FIRE SEASON PROTOCOLS.

A. The Companies held two EWG meetings to discuss the three enhanced fire season protocols. To assess the impact of these protocols on public safety,[7] NV Energy sent EWG meeting invitations to all public safety agencies listed in the original and current final regulations, all fire agencies in the NV Energy footprint, and Major Account customers. NV Energy also held separate Major Account customer meetings for Nevada Power and Sierra customers to ensure proper socialization.

All EWG members conceptually supported the emergency de-energization protocol. Some EWG members requested that NV Energy consider exclusion zones for de-energization, including fire response facilities and priority communication infrastructure. EWG members also requested the Companies consider using triangle polygons to represent predicted fire spread to define a de-energization boundary rather than the current approach, which uses a radius from the location of the fire start. The Companies will continue to collaborate with EWG members to develop measures that can be taken prior to activating the emergency de-energization protocol.

The Companies recognize the need for critical facilities customers and service providers to update business continuity and emergency response plans. Continuing education and outreach will be an ongoing NDPP activity as NV Energy continues to implement the protocols. Following the 2024 emergency

[7] *See* NRS 704.7983(1)(e). The Companies are required to assess the impact on public safety of de-energization of its distribution lines and disabling reclosers on those lines in the event of a fire or natural disaster. The Companies accepted feedback from the relevant stakeholders to mitigate the impacts of its protocols on public safety.

de-energizations, NV Energy debriefed impacted fire agencies, as well as community residents affected by 2024 fires, such as Washoe Valley residents.

27. Q. DO THE PROTOCOLS CHANGE THE COMPANIES' APPROACH TO OTHER NDPP PROJECTS OR PROGRAMS?

A. No. The enhanced fire season protocols are additional protection measures intended to address identified high-risk conditions. These measures are in addition to, not instead of, other mitigation measures. The Companies' commitment to implementing the risk mitigation measures approved in the Plan for the years 2024-2026 will not change with the adoption of the enhanced protocols contained in this First Amendment.

28. Q. ARE THE COMPANIES PROPOSING ANY INCREASE IN NDPP COSTS IN THIS FIRST AMENDMENT TO IMPLEMENT THE ENHANCED FIRE SEASON PROTOCOLS?

A. No, the Companies are not requesting any additional funding for implementation of the enhanced fire season protocols. Existing approved budgets are sufficient to cover the costs of these protocols, or in some cases, the Companies will seek approval of cost recovery in a future general rate case ("GRC").[8]

Beyond implementation of the protocols themselves, however, the Companies are requesting additional funding for additional situational awareness associated to new weather stations and wildfire cameras, as discussed in more detail in Mr. Hoon's testimony.

[8] The existing approved budget for PSOM is currently sufficient to cover the low likelihood of PSOM activations in Tier 1 through 2026. The Companies will seek cost recovery for de-energization and FTFM through a future GRC.

II. NEW PROPOSED NDPP PROGRAMS

29. Q. PLEASE PROVIDE AN OVERVIEW OF THE NEW NDPP PROGRAMS AND FUNDING REQUESTS INCLUDED IN THIS FIRST AMENDMENT.

A. The Companies are requesting funding for new NDPP-related programs in this First Amendment. The new NDPP programs include a combination of new technologies and new personnel that are incremental to the Companies' normal course of business and necessary to reduce risk from natural disaster. Table 11 in the First Amendment (**Exhibit B** to the Application) provides an overview of the proposed new NDPP programs and the headcount associated with each.

30. Q. PLEASE EXPLAIN THE HAZARD AWARENESS DESK AND THE RESOURCES NV ENERGY IS REQUESTING TO IMPLEMENT THIS NEW PROGRAM.

A. The hazard awareness desk will be a dedicated resource to monitor wildfire and other natural disaster risk 24 hours a day and 365 days a year. The desk will be staffed around the clock by one person and will be the first filter for validating credible hazard intelligence, dispatching the Companies' Fire Mitigation Officers, and initiating the Companies' immediate coordination for wildfire emergency prevention and response efforts.

Early detection is key to ensuring the Companies' optimal response to emergencies. Many utilities use hazard awareness centers to combat high fire risk and effectively monitor for potential natural disasters and ensure customer safety. Hazard awareness centers pool multiple sources of intelligence and communication into a single hub manned by personnel with expertise in fire, weather, and fire and other emergency operation responses. These centers are configured as a control center and have a direct tie into multiple public agency cooperative emergency dispatch centers to ensure the Companies receive direct and credible intel related to any hazard effecting the utility system.

The Companies evaluated hazard awareness centers at other utilities to design a single desk to monitor and expedite response to identified risk across both service territories. The Companies have most of the technology needed to formalize the desk, except for the Palantir Foundry technology discussed in more detail below. Additional details about the resources needed to staff this desk are provided in the First Amendment (**Exhibit B** to the Application).

31. Q. PLEASE EXPLAIN HOW THE HAZARD AWARENESS DESK IS INCREMENTAL TO THE COMPANIES' NORMAL COURSE OF BUSINESS.

A. The Companies currently do not have personnel qualified or dedicated to hazard awareness detection and communication. This hazard awareness desk supplements existing system control room operations for optimal coordination for fire and other extreme weather events. Increasing hazard awareness capability is necessary to protect utility infrastructure and minimize impacts from utility facilities. Many utilities throughout the West have implemented similar capabilities to protect against wildfire and other natural disaster risks.

32. Q. PLEASE PROVIDE THE PROPOSED BUDGET FOR THE HAZARD AWARENESS DESK.

A. The proposed 2024-2026 OMAG budget for the hazard awareness desk is presented in Table 12 in the First Amendment (**Exhibit B** to the Application). In total, the Companies are projecting $703,808 for Nevada Power in OMAG-related costs and $1,055,712, for Sierra in OMAG-related costs for the hazard awareness desk.

33. Q. PLEASE EXPLAIN THE NEED FOR THE NDPP-RELATED DISTRIBUTION AUTOMATION RESOURCES REQUESTED IN THIS FIRST AMENDMENT.

A. Simply put, some NDPP-related grid resilience operating practices, such as the enhanced fire season protocols, impact reliability as a tradeoff for increased public safety protection. Distribution automation can affect these tradeoffs by adding intelligent technology to the distribution system to reduce outages caused by NDPP-related activities. With the goal of reducing the reliability impact, the Companies are requesting approval to hire NDPP-related Distribution Automation personnel to coordinate, maintain, and expand the Companies' efforts to operate new fire mitigation technology and equipment. In particular, the distribution automation initiative will address NDPP emergency response impacts by enabling "smart" devices that will be used to remotely control the system, ultimately aimed at reducing the number of customers affected by outages, as well as reducing the duration of NDPP-related outages.

Details as to the specific functions for the proposed distribution automation personnel are addressed in the First Amendment (**Exhibit B** to the Application).

34. Q. PLEASE EXPLAIN HOW NDPP-RELATED DISTRIBUTION AUTOMATION IS INCREMENTAL TO THE COMPANIES' NORMAL COURSE OF BUSINESS.

A. The Companies currently do not have a department focused on field technology specific to distribution line automation or NDPP. As distribution lines automation makes up a specific portion of the NDPP efforts, it will be important to develop a team to specialize in and own this technology. Regional engineers who might be used for distribution automation are already fully utilized with day-to-day operations and are not able to proactively perform in-depth analysis to address potential miscoordinations on the distribution network or to improve system design to address NDPP-related initiatives, which could inadvertently create wildfire hazards or fail to address reliability concerns associated with outages that occur to reduce wildfire risk.

NDPP currently utilizes reclosers and TripSavers within the fire mitigation plans. However, there are several additional benefits that could be realized with a dedicated NDPP-specific distribution automation team. Generally, this team would:

- Study where additional devices are needed to better sectionalize circuits based in the fire Tier areas;
- Coordinate settings between devices like TripSavers, line reclosers, and substation breakers/reclosers to ensure proper operation during normal and fire season operations;
- Add communication to those field devices to allow for remote monitoring and control;
- Set up and maintain the operational technology for the program; and
- Install and maintain the field devices.

All these responsibilities will result in increased efficiencies over current practices. As an example, when devices, like TripSavers, need to be moved from normal operating mode to a fire season setting, a line crew needs to be dispatched to each location to move a manual lever. This can take considerable time. Due to the level of effort required, this is typically only done twice per year, at the beginning and at the end of the high-risk seasons. This distribution automation team would be able to implement communications technologies to allow for remote settings changes, which would be much more efficient and would allow the opportunity to fine-tune the timelines of when devices are switched between normal and fire season settings.

35. Q. PLEASE DISCUSS THE PROPOSED BUDGET FOR THE NDPP-RELATED DISTRIBUTION AUTOMATION.

Tables 13 and 14 in the First Amendment (**Exhibit B** to the Application) show the proposed OMAG and capital budgets for the NDPP-related Distribution Automation program. The Companies project approximately $142,000 in

OMAG and capital costs for Nevada Power and approximately $6 million in OMAG and capital costs for Sierra.

36. Q. PLEASE DESCRIBE THE AIDASH TECHNOLOGY THE COMPANIES PROPOSE TO IMPLEMENT THROUGH THIS AMENDMENT.

A. AiDash is a comprehensive vegetation management solution that enhances data gathering capabilities and leverages remote sensing and satellite imagery. Some attributes of AiDash include the use of satellite imagery in lieu of manual functions, such as patrols by vehicle. As an example, the Companies currently deploy third-party contract forester crews in trucks to patrol the Companies' infrastructure to identify areas requiring fuels clearing in the Rights of Way ("ROW"). Foresters write the scope of work based on their observations of vegetation growth and fuel conditions with forecasts for future vegetation management work largely based on when work was last performed and individual historical local knowledge of how fuels grow back. These activities take significant time and resources that can patrol hundreds of miles to remote areas to determine where work is needed. Utilizing satellite imagery increases efficiency and provides the ability to capture and store detailed data across hundreds of circuit miles.

The Companies will use AiDash satellite imagery to prioritize vegetation management and allocate resources. AiDash retains record of completed work, including the fuel types treated. AiDash performs a predictive analysis of the completed work, fuel types and weather patterns to estimate vegetation growth and subsequently help forecast what cycle frequency for vegetation management is needed. Considering the Companies' vegetation management efforts increased tenfold in scope due to the NDPP, leveraging available

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technology to optimize resource allocation is prudent and necessary to manage the logistics involved to monitor and respond efficiently to continued fuel growth.

The Companies are proposing the AiDash 18-month pilot program to explore opportunities to prioritize vegetation management efforts using enhanced technology. AiDash is anticipated to validate vegetation management improvements to improve forecasted vegetation management cycles by geographic area. An intelligent vegetation management system can optimize resources to efficiently lower risk and potentially lessen the likelihood and impact of de-energization events. AiDash is one of multiple vendors offering this service. The Companies intend to use the results of the AiDash pilot program to inform a future formal RFP event from which comparisons can be made.

37. Q. PLEASE EXPLAIN HOW THE AIDASH TECHNOLOGY IS INCREMENTAL TO THE COMPANIES' NORMAL COURSE OF BUSINESS.

A. The Companies' do not currently have technology with the AiDash capabilities described above. Many utilities across the West are exploring similar AI-based technologies that can better direct vegetation management efforts. The pilot is narrowly scoped to determine whether AiDash can provide long term benefits.

38. Q. PLEASE DESCRIBE THE PALANTIR FOUNDRY TECHNOLOGY THE COMPANIES PROPOSE TO IMPLEMENT THROUGH THIS AMENDMENT.

Palantir Foundry is a data analytics platform to aid natural disaster mitigation operations, including fire season protocols such as PSOM and FTFM. Palantir Foundry will utilize existing functionality to integrate data across multiple separate systems into a common operating picture for real-time decision making during periods of natural disaster risk, supporting tracking and data retention. Palantir Foundry is the only known provider of mission-critical natural disaster risk mitigation information technologies with capabilities for PSOM event management, FTFM settings, and related data retention and reporting.

The Companies intend to leverage collaboration for Palantir Foundry with PacifiCorp to take advantage of PacifiCorp's experience with this platform. The Companies will use the model developed by PacifiCorp to standardize fire incident and PSOM data collection and retention.

39. Q. PLEASE EXPLAIN HOW THE PALANTIR FOUNDRY TECHNOLOGY IS INCREMENTAL TO THE COMPANIES' NORMAL COURSE OF BUSINESS.

A. Palantir Foundry is a data analytics platform that is incremental to existing tools that support natural disaster mitigation operations, including fire season protocols such as PSOM and FTFM. The Companies currently lack the ability

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to integrate data and information from the separately managed existing systems associated with NDPP. Today, most processes, such as fire incidents and PSOM, are highly manual and lack intelligence for predictive analysis, automated recall, or ability to cross-reference. Foundry connects models and data iteratively over time to create operational workflows and more sophisticated analytics to reduce risk using a continuous learning loop. Foundry processes key data attributes to spatially recognize where wildfire risks exist to help more precisely switch the electrical system at critical junctures. Over the longer term, Foundry identifies fire activity and cause determinations that can uniquely benefit NDPP for continuous intelligent risk reduction.

Palantir will benefit customers though its capabilities of automatically creating customer notifications and data packages for sharing with the EWG collaborators; and through integrating existing databases, eliminating the need for manual manipulation to improve the timeliness and accuracy of customer and EWG outreach. This will reduce operational planning and implementation errors and data loss.

40. Q. PLEASE DISCUSS THE PROPOSED EMERGING TECHNOLOGY AND STRATEGIES BUDGET FOR PALANTIR FOUNDRY AND AIDASH TECHNOLOGY.

A. Table 15 in the First Amendment (**Exhibit B** to the Application) shows the Companies' request to increase funding for the Emergent Technologies and

Strategies budget to implement Palantir Foundry and facilitate a pilot project using AiDash for vegetation management.

MOUNT CHARLESTON REBUILD PHASE 1 MODIFICATION

41. Q. PLEASE DESCRIBE THE STATUS OF AND FIRST AMENDMENT PLAN FOR THE MOUNT CHARLESTON REBUILD.

A. In the Plan, the Companies presented a four-phase plan to rebuild and ruggedize facilities at Mount Charleston. The Commission approved $15.9 million dollars for the Mount Charleston rebuild for the 2024-2026 triennium. The Companies have continued to evaluate options for ruggedization for the Mount Charleston communities located in a Tier 3 wildfire risk area.

In this Application, the Companies present a modified plan to the proposed Phase 1 that would implement a fire season activated microgrid using a combination of solar photovoltaic ("PV") generation, battery energy storage system ("BESS"), and propane generation to replace the previously approved Northwest ("NW") 1215 to Kyle Canyon Feeder Tie. The microgrid configuration is a candidate for Grid Resilience and Innovation Partnership ("GRIP") grant funding from the Department of Energy ("DOE") which could further offset costs.

In the revised Phase 1, Nevada Power will procure and implement a fire season activated microgrid using a combination of solar PV, BESS, and propane generation. The microgrid will have a 50 percent renewable profile. Nevada Power will also reconductor the existing Kyle Canyon 1201 circuit with Tier 3 construction standards that include covered conductor, ductile iron poles, fire mesh wrap technology, and non-expulsion fuses. Finally, Phase 1 will include site maintenance to the Kyle Canyon substation to include enhanced drainage, retaining walls, and other basic improvements. The Companies also anticipate potential cost offsets from a GRIP grant award that is currently under negotiation with the DOE.

42. Q. WHAT FUNDING IS NV ENERGY REQUESTING FOR THE MOUNT CHARLESTON REBUILD?

A. As shown in Table 16 in the First Amendment (**Exhibit B** to the Application), these filing requests funding approval for the amended Phase 1 microgrid configuration. NV Energy is requesting an additional $3.5 Million through 2026 to implement Phase 1.

The clean energy microgrid solution is planned to run in parallel with Kyle Canyon 1201 so that the solar PV can provide renewable energy benefits to the system in addition to resilience in the Mount Charleston area. This approach is more cost-effective than the original proposed solution of more than $70 million and any of the other rebuild or new feeder options analyzed. The alternatives analyzed are presented in an appendix to the First Amendment request (**Exhibit B** to the Application). When combined with system hardening to reconductor the Kyle Canyon 1201 line, the microgrid solution also provides the best risk reduction.

In addition to the capital costs discussed above, NV Energy estimates approximately $100,000 in annual operation and maintenance costs and $160,000 in annual fuel costs for the microgrid solution.

43. Q. PLEASE EXPLAIN THE BENEFIT TO CUSTOMERS FROM THE MOUNT CHARLESTON MICROGRID PLAN.

A. There are several benefits to the microgrid plan. The Mount Charleston region will become separated into two different proactive de-energization zones: Angel Peak and Kyle Canyon. Based upon historical weather data, most PSOM events for Mount Charleston are from the weather conditions present on top of Angel Peak. Weather conditions in Kyle Canyon meet the PSOM criteria in only about 20 percent of those events. Thus, Kyle Canyon residents and businesses will see a great reduction in PSOM events per year. The microgrid option reduces permitting requirements and eliminates need for a new feeder tie from Northwest ("NW") substation and associated undergrounding. The previously proposed distribution feeder tie consisted of installing approximately eighteen miles of new underground electric infrastructure from the Northwest substation to Kyle Canyon substation. Thirteen miles of the proposed feeder tie extended through Tier 1 before reaching Tier 3. The modified Mt. Charleston rebuild plan, specifically the addition of the microgrid at or around the Spring Mountain visitors center located within Tier 3, eliminates the need for the new feeder tie. This change subsequently results in an overall cost saving of approximately $25 million dollars.

44. Q. TO DATE, HAVE THE COMPANIES INCURRED COSTS RELATED TO THE APPROVED MOUNT CHARLESTON RUGGEDIZATION PLAN?

A. Yes. The Companies included costs for initial assessment of routing and sourcing options in the 2023 NDPP cost recovery filing.

III. FIRE TIER MAP CORRECTIONS

45. Q. PLEASE EXPLAIN THE COMPANIES' REQUEST TO MODIFY FIRE TIER MAPS.

A. NV Energy is requesting approval for minor modifications to the fire Tier area map for the Mount Charleston and Lake Tahoe areas. These modifications are necessary to correct errors in the previously approved maps. The cross-hatched sections in the maps indicate the corrections needed for these distribution circuit segments. The maps submitted as part of the NDPP filing failed to pick up these segments. The Companies are not requesting additional funding to address these changes currently. Work for these areas will be prioritized among other planned work such as patrols and inspections, vegetation management, and assessment for conversion to a covered conductor alternative where applicable.

Figure 5 in the First Amendment (**Exhibit B** to the Application) shows an update to the Tier 1 boundary in the Mt. Charleston area to add 2.4-line miles of the Canyon 3401 distribution circuit and 35 poles. Figure 6 in the First Amendment (**Exhibit B** to the Application) shows an update to the Tier 2 boundary in the Lake Tahoe area to add 4-line miles of the Steamboat 212 distribution circuit and 96 poles. This segment is located at the tail end of the circuit at the very top of Mt. Rose at the radio towers. This is the area that was literally in the line of forecasted fire run for at least one scenario during the Davis fire.

46. Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT HOWARD-DIRECT-1

Statement of Qualifications
for
DANYALE M. HOWARD

Professional Experience

Director, Natural Disaster Protection Plan
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
June 2021 - Present

Responsible for developing and implementing the Natural Disaster Protection Plan ("NDPP") mitigation programs and projects, controls, technology development, engineering, resource allocation and program effectiveness.

Director, Distribution Design Services, Northern Nevada
Sierra Pacific Power Company d/b/a NV Energy
April 2018 – June 2021

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to Public Utilities Commission of Nevada ("PUCN") Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

Manager, Distribution Design Services, Northern Nevada
Sierra Pacific Power Company d/b/a NV Energy
January 2016 – April 2018

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to PUCN Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

Supervisor, Distribution Design Services
Sierra Pacific Power Company d/b/a NV Energy
March 2013 – January 2016

Responsible for electric and gas design engineering and project coordination for distribution line extensions and facility relocation projects subject to PUCN Rule 9 tariff, local government franchise agreements and electric planned capital maintenance targets. Managed Truckee Meadows and Carson City offices.

Team Leader, Field Services, Northern Nevada
Sierra Pacific Power Company d/b/a NV Energy
January 2011 – March 2013

Responsible for developing, implementing, and supervising procedures for reading and data collections, accurate and cost-effective installation of electric meters and gas AMI modules. Managed staff across nine rural district locations.

Utility Design Administrator II
Sierra Pacific Power Company d/b/a NV Energy
October 2004 – January 2011

Responsible for performing design and project management of electric and gas distribution projects. Participated in the implementation of the Enterprise Work Asset Management ("EWAM") project, creating business test scenarios, regression and user acceptance testing, and facilitated training across all northern Nevada districts.

Analyst II, Revenue Protection
Sierra Pacific Power Company d/b/a NV Energy
December 1997 – October 2004

Responsible for preparing and submitting exhibits, reports and legal documents related to utility theft and fraud. Past president of Western States Utility Theft Association ("WSUTA"), responsible for coordinating training and certification to utility investigators nationally.

Meter Reader
Sierra Pacific Power Company d/b/a NV Energy
May 1997 – December 1997

Responsible for collecting and recording accurate meter reads for electric and gas meters.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, DANYALE HOWARD, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Danyale Howard

Date: December 17, 2024

DANYALE HOWARD

ALEXANDER HOON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
and Sierra Pacific Power Company d/b/a NV Energy

First Amendment to the 2023 Natural Disaster Protection Plan
Docket No. 24-12XXX

Prepared Direct Testimony of

Alexander Hoon

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Alexander Hoon. My current position is Principal Meteorologist, Natural Disaster Protection for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Principal Meteorologist, I provide key decision support to leadership and operations for extreme weather that could result in natural disasters, including wildfires. I serve as the Companies' subject matter expert for all weather-related matters, including fire weather, and advanced risk modeling. I am responsible for short- and long-term weather forecasting and technical leadership for the

Companies' Situational Awareness programs. As a lead for the situational awareness systems, my expertise includes weather stations, wildfire cameras, artificial intelligence ("AI") and wildfire risk modeling technologies.

3. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I joined NV Energy in October 2021. For the previous 15 years I worked for the National Weather Service in Reno, Nevada where I was the Fire Weather Program Manager and Incident Meteorologist. I have been deployed to more than 25 major wildfires across the western United States. My experience is primarily in fire weather, fire behavior, and operational weather decision support.

My statement of qualifications is attached as **Exhibit Hoon-Direct-1.**

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I submitted testimony in the 2024-2026 Second Triennial Natural Disaster Protection Plan ("NDPP") filing in Docket No. 23-03003 and the Companies' application for NDPP Regulatory Asset Recovery in Docket No. 24-03006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide insight into NV Energy's proposed First Amendment ("First Amendment") to the 2024-2026 NDPP. Specifically, I will discuss how expanding Public Safety Outage Management ("PSOM"), implementing Fast-Trip Fire Mode ("FTFM"), and improving situational awareness through the deployment of additional wildfire cameras and weather stations will enhance Nevada's resilience to wildfire risks. I will also address how emergency de-energization protocols further mitigate wildfire hazards by cutting power during imminent fire risks. These measures aim to reduce the likelihood of powerline-initiated wildfires and protect public safety, infrastructure, and natural resources across the State of Nevada.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following Exhibits:

Exhibit Hoon-Direct-1, Statement of Qualifications

Exhibit B to the Application, the First Amendment to the Second Triennial NDPP for plan years 2024-2026. Specifically, I sponsor or co-sponsor the following portions of the First Amendment:

- Section 2.3 – Situational Awareness
- Section 2.2.1 – Expanded PSOM
- Section 2.2.2 – FTFM
- Section 2.2.3 – Emergency De-Energization
- Appendix B to Exhibit B, NV Energy's Emergency De-Energization Wildfire Policy.

7. Q. ARE THE COMPANIES REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION IN THIS FILING?

A. Yes. Appendix B to Exhibit B, NV Energy's Emergency De-Energization Wildfire Policy, contains confidential information pursuant to Nevada's Homeland Security

Act, codified in NRS §239C.210 and Federal Laws relating to Critical Energy Infrastructure Information and Controlled Unclassified Information.

8. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. The Emergency De-Energization Wildfire Policy includes detailed information regarding NV Energy's infrastructure and its operational practices in certain emergency response situations. As a result, NV Energy has designated this information confidential pursuant to NRS § 703.190 and NAC § 703.5274.

9. Q. FOR HOW LONG DOES NV ENERGY REQUEST CONFIDENTIAL TREATMENT?

A. Given the sensitive nature of the information involved, NV Energy requests permanent confidential treatment of the Emergency De-Energization Wildfire Policy.

10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO PARTICIPATE IN THIS DOCKET?

A. No. In accordance with the accepted practice in Commission proceedings, the confidential material can be provided to Staff and the BCP under standardized protective agreements with them.

11. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four key sections:

Situational Awareness Enhancements: This section highlights the importance of real-time monitoring using wildfire cameras and weather stations to detect and respond to fire risks. I discuss how improved situational awareness allows NV Energy to take proactive steps to mitigate potential wildfire threats.

Expanded PSOM: In this section, I explain the rationale for expanding PSOM across all fire risk areas in Nevada, detailing how this measure will help prevent powerline-initiated wildfires during high-risk conditions.

FTFM: I, along with NV Energy witness Joshua Icenhower, address the necessity of FTFM given Nevada's increasing fire risks due to changing climate conditions.

Emergency De-Energization: I explain how Emergency De-Energization is used as a proactive safety measure when there is an imminent threat from an existing wildfire.[1] This section highlights how Emergency De-Energization serves as an additional layer of protection for the Companies' infrastructure and the communities it serves.

The testimony is structured to show how these combined initiatives work together to mitigate wildfire risks, improve grid resilience, and enhance public safety.

[1] NV Energy witness Danyale Howard provides more details on Emergency De-Energization. The First Amendment, Exhibit B to the Application, also more details on the Companies' Emergency De-Energization Wildfire Policy.

SITUATIONAL AWARENESS ENHANCEMENTS

12. Q. WHY IS SITUATIONAL AWARENESS ESSENTIAL FOR WILDFIRE PREVENTION AND MITIGATION?

A. Situational awareness is critical for identifying and managing risks in real-time, particularly in wildfire-prone areas. In Nevada, where climate change has increased the frequency of high-risk weather conditions such as prolonged droughts and high winds, enhanced situational awareness allows NV Energy to detect these wildfire risks early. Situational awareness enables preventive measures like PSOM, FTFM, and Emergency De-Energization, to mitigate potential wildfire outbreaks before they escalate. It also allows for timely responses in collaboration with Expert Working Group partners in emergency situations, protecting communities and infrastructure.

13. Q. HOW DO WILDFIRE CAMERAS AND WEATHER STATIONS CONTRIBUTE TO SITUATIONAL AWARENESS?

A. Wildfire cameras provide continuous, real-time monitoring of wildfire risk by enabling early detection of smoke, flames, or other fire indicators. These wildfire cameras consist of a combination of long-range cameras and short-range cameras. Long-range wildfire cameras are typically placed on mountain tops or areas with very large viewsheds to detect wildfires up to 10 miles away or more. Short-range cameras are placed directly on distribution or transmission poles to view smaller areas for potential ignitions in extreme-risk Tier 3 areas. In 2024, FireBIRD short-range cameras[2] were successfully piloted in the Mt. Charleston area.

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[2] FireBIRD is the name of an autonomous fire detection/weather station technology that is made by a company called Lindsey FireSense. Each FireBIRD device has eight cameras, six pointed in a downward direction and two lateral view cameras. These are to be used on targeted key right-of-ways to try to detect wildfires that are threatening or potentially caused by the electrical grid.

Weather stations collect and analyze data on wind speed, temperature, humidity, and other meteorological factors that influence fire behavior. By placing weather stations in fire-prone areas, the Companies can monitor conditions that contribute to damaging or potentially catastrophic wildfires.

Together, these important situational awareness tools offer a more comprehensive picture of current environmental conditions, allowing the Companies to identify potential wildfire threats promptly and accurately, thereby enhancing the Companies' ability to respond effectively through actions such as PSOM and Emergency De-Energization.

14. Q. HOW WILL EXPANDING THE USE OF WILDFIRE CAMERAS AND WEATHER STATIONS BENEFIT NEVADA'S FIRE-PRONE AREAS?

A. Expanding deployment of wildfire cameras and weather stations will enhance the Companies' ability to detect threats across a broader geographic range in identified wildfire risk areas. This includes the newer Tier 1 areas established in the 2023 NDPP Triennial Plan, which currently have little to no coverage from wildfire cameras or weather stations, as well as filling in any necessary gaps that have been identified in Tier 3, 2, and 1E areas.

This expansion will significantly improve real-time data collection, enabling the Companies to monitor identified wildfire risk areas, especially during peak fire seasons. Precise and timely data informs conditions that could lead to wildfires.

This opens critical time windows to improve the safety alerts to and responses for impacted communities.

EXPANDED PSOM

15. Q. WHAT IS NV ENERGY REQUESTING IN THIS CASE REGARDING EXPANSION OF PSOM?

A. The Companies request to implement PSOM systemwide. Previously, NV Energy has been granted approval to conduct PSOM for Tiers 3, 2, and 1E. The previous expansion of PSOM into Tier 2 and 1E areas was approved by the Commission in the Order in Docket No. 21-03040.

The proposed expansion of PSOM systemwide was first raised as an operational practice in the NDPP Progress Report in Docket No. 24-07003. Additional detail regarding the expansion of PSOM systemwide is provided in the Section 2.1.1 of the Plan's First Amendment.

16. Q. WHY IS NV ENERGY EXPANDING PSOM ACROSS ITS SERVICE TERRITORIES?

A. PSOM is a key wildfire prevention strategy that involves proactively de-energizing power lines during the most extreme fire weather conditions to prevent electrical equipment sparks that could ignite wildfires. By expanding PSOM, customers will benefit from increased protection against wildfires caused by electrical infrastructure. An expanded PSOM similarly ensures that even lower-risk or previously unmonitored areas receive the same level of protection as the highest-risk zones. Although PSOM may result in temporary power outages during critical conditions, it significantly reduces the risk of damage from catastrophic wildfires.

Moreover, an expanded PSOM helps to alleviate public safety concerns and mitigates potential environmental impacts and economic costs systemwide. Public safety concerns include the potential for increased property damage, including destruction of structures, infrastructure, evacuations, injuries, and loss of life in extreme events. Environmental impacts include habitat destruction and loss of wildlife. The economic costs associated with firefighting efforts, property damage, loss of livestock, and loss of revenue from disrupted businesses could be substantial, impacting both individuals and the broader economy. These proactive outages prevent the ignition of fires, ultimately protecting homes, businesses, and natural resources.

As the frequency and severity of wildfires and adverse weather events increase, rigorous protocols for proactive de-energization have become the industry standard for public safety when extreme conditions are present. PSOM is a critical measure to address an imminent wildfire on the electric system. PSOM is not viewed in isolation but as part of a multifaceted natural disaster mitigation strategy. As climate change increases fire risks across the state, PSOM provides a consistent data-driven approach to mitigating wildfires. Expanding PSOM to the Companies' entire service territories ensures that no community is left vulnerable due to geographical location.

17. Q. WHAT ARE THE RISKS OF NOT EXPANDING PSOM SYSTEMWIDE?

A. The risks associated with not expanding PSOM and related monitoring to all of the Companies' overhead system results in differentiated risk reduction among customers. Given the inherent imprecision of forecasts and risk models, extending PSOM systemwide offers a level of risk reduction to all customers, including those in disadvantaged and remote communities, from a utility-related ignition. As the effects of climate change result in increasingly intense and frequent weather events, the Companies will continue to monitor and model the trends related to natural disasters and adjust the NDPP accordingly. Future filings will timely indicate any immediate findings and the triennial report will incorporate climate insights and related weather impacts to the service territories. This is especially important given the trend of more frequent, extreme weather, and the lack of a mitigation strategy can be devastating, as evidenced by the impacts of wildfires in recent years in California, Colorado, Hawaii, Texas, and Oregon.

18. Q. HOW WILL NV ENERGY ENSURE THAT PSOM IS EFFECTIVELY IMPLEMENTED SYSTEMWIDE?

A. NV Energy will use data from weather stations, wildfire cameras, and advanced weather and wildfire modeling systems to identify the potential for extreme conditions in forecasts and in real-time. The tools that the Companies use to identify extreme conditions include situational awareness dashboards from Cloudfire,[3] wildfire risk modeling from Technosylva, as well as weather station data and wildfire camera imagery from NV Energy and other publicly shared data. By

[3] https://nvfireweather.com

integrating this information, the Companies can make timely decisions about when and where to initiate PSOM.

Additionally, the same PSOM process the Companies use today will be applied consistently across all areas, including the same communication and coordination plans provided in the PSOM plan, previously provided as Appendix A in Docket No. 24-07003.[4] The Companies continue to collaborate with the Expert Working Group to harmonize wildfire mitigation and response. Regular reviews and updates to PSOM protocols ensure the program remains effective as fire risks evolve.

FAST-TRIP FIRE MODE

19. Q. WHAT IS THE CURRENT STRATEGY FOR FIRE SEASON SYSTEM SETTINGS ON THE ELECTRICAL GRID?

A. Seasonal Fire Mode is the current strategy of electrical system settings that the Companies use for reducing the risk of faults causing a wildfire. "Seasonal Fire Mode" means the same thing as NV Energy's reference to Fire Season No-Reclose Mode, which means that during fire season, this mode disables reclosing on Tier 3, 2, and 1E circuits. Although disabled reclosing is a good strategy that has been successful in the past, there is newer, more advanced technology that exists that even further reduces the risk of wildfires from electrical faults. FTFM is an example of the more advanced technology that is now available to reduce wildfire risk.

20. Q. WHAT IS FTFM, AND WHY IS IT BEING IMPLEMENTED NOW?

A. FTFM is an advanced grid safety feature designed to rapidly de-energize power lines in response to abnormal electrical activity, such as faults caused by high winds

[4] The updated PSOM plan is filed in this case as Appendix A to Exhibit A to the Application.

or damaged infrastructure. The technical details about FTFM and how it is implemented are addressed in the Prepared Direct Testimony of NV Energy witness Mr. Icenhower in this docket. FTFM rapid response is critical in high or very high fire danger conditions, providing an additional layer of protection between Fire Season No-Reclose Mode and PSOM protocols.

21. Q. ON AVERAGE, HOW LONG WILL THESE SETTINGS BE IN PLACE EACH YEAR FOR EACH OF THESE AREAS?

A. Because the fire assessment system, the Severe Fire Danger Index ("SFDI")[5] is based on the product of Energy Release Component and Burning Index risk percentiles for all days in the year, NV Energy can estimate the average number of days per year for each area will be placed into Seasonal Fire Mode and FTFM settings.

1. NV Energy will place all Tier 3, 2, and 1E circuits in Fire Season No-Reclose Mode once the SFDI enters the Moderate Fire Danger category, which is greater than 60th percentile of all days. This is about 146 days of the year, or approximately five months each year on average.
2. The Companies will implement FTFM settings in Tier 3 areas when the SFDI indicates High Fire Danger or above, which corresponds to the 80th percentile. That means that for about 20 percent of days, FTFM settings will be in place for Tier 3 areas. This is approximately 73 days of the year, or approximately two months each year on average.
3. The Companies will initiate FTFM settings in Tier 2 and Tier 1E when the SFDI indicates Very High Fire Danger or above, which corresponds to the

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[5] https://m.wfas.net/dev/.

90th percentile or above. This corresponds to the top 10 percent of fire danger days, or about 36 days of the year, or approximately one month each year on average.

Even though these are the average number of days for each area, each fire season will be different. Some seasons will be more intense, with longer periods of High Fire Danger or Very High Fire Danger, and some seasons will be less intense.

22. Q. WHY IS FTFM NECESSARY GIVEN NEVADA'S CURRENT WILDFIRE CLIMATE?

A. FTFM provides a timely and practical approach to de-energize lines using protective devices when an anomaly is detected on the power grid. FTFM reduces the likelihood of wildfires sparked by electrical infrastructure during of High Fire Danger and/or Very High Fire Danger events when ignitions are more likely to occur. The level of imprecision in NV Energy's models and forecasts combined with the long timelines to fully implement grid hardening and vegetation management projects make it prudent to have additional stop-gap protection protocols like FTFM.

23. Q. HOW DOES FTFM COMPLEMENT OTHER WILDFIRE PREVENTION MEASURES LIKE PSOM?

A. While PSOM focuses on preemptively shutting off power during known high-risk weather conditions, FTFM provides an automated response to unexpected electrical faults in real-time. These two systems work in tandem: PSOM prevents the possibility of power-line initiated wildfire during extreme weather periods, while

FTFM responds to immediate, unforeseen threats on High Fire Danger or Very High Fire Danger days that are typically below the criteria established for PSOM. Together, they create a complementary defense against infrastructure-initiated wildfires, significantly improving the safety and resilience of Nevada's electrical grid.

EMERGENCY DE-ENERGIZATION

24. Q. WHAT IS EMERGENCY DE-ENERGIZATION, AND WHY IS IT NECESSARY?

A. Emergency de-energization is the process of rapidly shutting down parts of the electrical grid when there is an imminent risk from an encroaching wildfire to prevent additional ignitions from electrified power lines. By cutting power to lines that are close proximity to an existing wildfire, the Companies reduce the risk of sparks igniting secondary fires, even in the most severe conditions.

25. Q. HOW IS EMERGENCY DE-ENERGIZATION DIFFERENT FROM PSOM OR FTFM?

A. Emergency de-energization is a proactive measure that is taken after a wildfire has already ignited in the vicinity of the Companies' equipment. PSOM and FTFM are proactive protocols designed to prevent issues before they arise. PSOM is used during forecasted extreme weather events, and FTFM is an automated system response to specific electrical anomalies during times of High Fire Danger or Very High Fire Danger. Emergency de-energization, on the other hand, is a broader, immediate action taken when an active wildfire is posing a direct threat to energized power lines.

26. Q. HOW WILL NV ENERGY DECIDE WHEN TO INITIATE EMERGENCY DE-ENERGIZATION?

A. An emergency de-energization condition occurs when a wildfire is reaching established safety boundaries from the Companies' facilities. There is an increased risk of additional ignitions if the wildfire makes contact with energized facilities. Because wildfires can rapidly spread based on different variables, the safety distances are pre-defined and encroachment risk is based on data-driven wildfire spread pattern projections.

CONCLUSION

27. Q. WHY ARE THESE CHANGES NECESSARY, AND HOW DO THEY BENEFIT THE STATE OF NEVADA?

A. Expanding PSOM to systemwide, implementing FTFM, establishing an Emergency De-Energization Policy and bolstering situational awareness with additional wildfire cameras and weather stations are necessary steps to lower Nevada's wildfire risks and foster resiliency for the Companies' network. By adopting these safety measures, NV Energy can better protect communities, infrastructure, and natural resources. These changes also align with state and federal goals for wildfire mitigation, ensuring that Nevada remains resilient in the face of growing environmental challenges.

28. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT HOON-DIRECT-1

STATEMENT OF QUALIFICATIONS OF

Alexander D. Hoon
Principal Meteorologist, Natural Disaster Protection
NV Energy
6100 Neil Rd. Reno, NV 89511
(775) 298-9050 alexander.hoon@nvenergy.com

Mr. Hoon has been an employee of NV Energy since 2021, but has 20 years of operational weather forecasting experience. He has worked in many positions through his career, from the U.S. Air Force to the National Weather Service, specializing in fire weather and emergency response. Mr. Hoon has a Bachelor of Science degree in Atmospheric Science. He is also a veteran Incident Meteorologist and has deployed to over 25 major wildfire incidents across the Western U.S. to provide critical weather data to fire leadership and firefighters in field.

Professional Experience

Principal Meteorologist, Natural Disaster Protection – NV Energy, Reno, NV ▪ 2023 – present

- Provides technical leadership on the most complex and business critical projects.
- Provides routine and non-routine operational weather forecasts to the utility.
- Leads large projects to develop, deploy and improve operational forecasting methods and models. Guides and leads projects that improve operational decision-making during storm and fire weather events.
- Participates in cross functional teams, including other meteorologists in and outside the company, data scientists, project and product managers, leadership, and subject matter experts to develop data driven solutions.
- Oversees a wide range of meteorological data to provide continuously updated weather information from a variety of sources to better manage the impacts of weather on the electric distribution and transmission system to identified vulnerabilities.
- Serves as the company's subject matter expert for all fire weather-related matters.

Senior Meteorologist, Natural Disaster Protection – NV Energy, Reno, NV ▪ 2021 – 2023

- Prepared and disseminated operational weather reports prior to and during significant weather events, including Public Safety Outage Management (PSOM) events.
- Integrated a wide range of meteorological data to provide continuously updated weather information to better manage the impacts of weather on the electric system and identified vulnerabilities.
- Monitored and reported to upper management real-time and forecast weather conditions on a recurring basis during storm events and major construction operational events.
- Continually maintained and enhanced procedures for monitoring the company's weather network and associated alerting, including the siting of new weather stations and fire cameras.
- Improved all real-time and operational forecasts through process improvements via new technologies and advancements.
- Worked closely with engineering and operational organizations to integrate weather information into fire risk mitigation and system hardening projects.
- Served as the company's subject matter expert for all fire weather-related matters.

Senior Meteorologist and Incident Meteorologist – National Weather Service, Reno, NV ▪ 2010 – 2021

- Served as the shift leader responsible for quality and timeliness of all National Weather Service (NWS) forecast and service products, warnings, and advisories prepared and issued by the Weather Forecast Office (WFO).
- As incident meteorologist, embedded with Incident Management Teams to work with operations, logistics, safety, and planning of emergency situations. Briefed teams, cooperators, community leaders, public safety, and general public on the weather threats that are specific to their areas of concern.

General Meteorologist** – **National Weather Service**, **Reno, NV ▪ 2006 – 2010

- Conducted a weather watch which involved interpretation of Doppler radar data, satellite imagery, and the analysis of other hydrometeorological data for the preparation of all WFO warning, forecast and service products, including individual briefings.
- Served as primary contact with other Federal, state, and local agencies such as Federal Aviation Administration (FAA), Federal Emergency Management Agency (FEMA), and emergency management and law enforcement officials over matters involving the initiation and implementation of immediate or emergency public health and safety measures based on NWS forecasts, warnings and watches.

Weather Officer, Lead Forecaster** – **U.S. Air Force**, **Scott AFB, IL ▪ 2003 – 2006

- Directed complex forecast production processes through detailed weather analysis and numerical model interpretations.
- Provided written forecast guidance and daily weather briefings to squadron and field unit forecasters that was leveraged in producing and disseminating tailored regional graphics, DOD installation forecasts, weather watches, warnings, and advisories, as well as air crew mission forecasts.

Education and Certifications

Bachelor of Science in Atmospheric Science – Texas A&M University, College Station, TX ▪ 2003
Type 1 Incident Meteorologist – National Wildland Coordinating Group ▪ 2011

Nevada Power Company
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d/b/a NV Energy

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ALEXANDER HOON, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: December 17, 2024

ALEXANDER HOON

JOSHUA ICENHOWER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
and Sierra Pacific Power Company d/b/a NV Energy

First Amendment to the 2023 Natural Disaster Protection Plan
Docket No. 24-12XXX

Prepared Direct Testimony of

Joshua Icenhower, PE

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Joshua Icenhower. I am the System Protection Engineering Manager for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power "NV Energy" or the "Companies"). I work primarily out of the Ohm Place complex in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. As Manager of System Protection Engineering, I am responsible for overseeing the technical studies and establishing the settings of devices used to protect NV Energy's transmission and distribution infrastructure. These protective devices ensure the safety and reliability of the electric grid, particularly in high-risk environments, such as those susceptible to wildfires.

3. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have been employed by NV Energy for five years. I hold a Bachelor of Science in Electrical Engineering and I am a licensed Professional Engineer in both Nevada and California. Over the past decade, I have held various roles within the electric utility industry, including positions related to hydro generation, substation design and commissioning, and substation operations, and maintenance. For the last three years, I have managed system protection engineering.

My statement of qualifications is included as **Exhibit Icenhower-Direct-1**.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. No, this is my first time submitting testimony before the Commission.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support NV Energy's proposed First Amendment ("First Amendment") to its 2024-2026 Natural Disaster Protection Plan ("NDPP"), specifically the Companies' implementation of the Fast Trip Fire Mode ("FTFM") system protection protocols. My testimony explains the rationale behind FTFM implementation, its operational principles, its benefits, and the strategic steps NV Energy is taking to mitigate wildfire risk while balancing reliability and safety. My testimony, along with Prepared Direct Testimony of the Companies' witness Danyale Howard, also supports the Companies' proposed new distribution automation resources to support NDPP.

6. Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is structured as follows:

- For FTFM:

- Overview of FTFM: A technical description of FTFM and its functionality.
- Industry Practices and Research: A discussion of leading industry practice findings from Pacific Gas & Electric's ("PG&E's") fast trip relay protocols, and how FTFM aligns with those findings.
- Customer Impacts and Benefits: An analysis of how FTFM enhances safety and the tradeoffs of that increased safety, including potential impacts of increased outages.
- Mitigation Strategies: A discussion on how NV Energy is mitigating reliability impacts associated with FTFM through its NDPP initiatives.

- For Distribution Automation:
  - New Positions: I support the proposed new positions that support increased reliability to balance the NDPP programs that could result in additional outages from system protection schemes.

7. Q. WHAT EXHIBITS AND APPENDIXES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following Exhibits:

Exhibit Icenhower-Direct-1, Statement of Qualifications

Exhibit Icenhower-Direct-2, Assessment of Hot and Flaming Particles and Fire Risk from High Current Faults

Exhibit Icenhower-Direct-3, Enhanced Powerline Safety Setting Program Overview from PG&E

Exhibit B to the Application, the First Amendment to the 2024-2026 Second Triennial NDPP. Specifically, I sponsor or co-sponsor the following portions of the First Amendment:

- Section 2.2.2 – Fast Trip Fire Mode

- Section 2.4.1 – Personnel to Implement New Initiatives.

I. FAST TRIP FIRE MODE

8. Q. WHAT IS FTFM AND HOW WILL IT MITIGATE THE COMPANIES' FIRE RISK?

A. FTFM is a protective measure designed to mitigate wildfire risk by shortening the response time of protective relaying on distribution circuits during fault events. Under normal relay operations, the protection system will trip after a brief delay to isolate faults. The protection system will then attempt to reclose – and re-energize the circuit – to test whether the abnormal condition has cleared. Using this approach during fire season could result in unintended arcing or sparking with the potential to ignite a wildfire. During fire season, select circuits in heightened fire risk areas are set to Seasonal Fire Mode. "Seasonal Fire Mode" means the same thing as NV Energy's reference to Fire Season No-Reclose Mode, where the circuit is operated so that reclosing is disabled. Additionally, in Fire Season No-Reclose Mode, there is a brief delay while tripping sequential portions of circuits until the fault is isolated. This delay helps maintain coordination between fuses and/or protective relays and is designed to leave portions of the circuit that are still in normal condition in service.

On days when FTFM is activated due to extreme fire weather conditions, the relays are set to trip almost instantaneously – within 0.1 second – when a fault is detected. This rapid response reduces the risk of electrical equipment being the source of an ignition. However, it eliminates fuse coordination, potentially resulting in more outages.

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9. Q. WHAT DOES IT MEAN TO BE FTFM CAPABLE?

A. Being FTFM capable means that the utility's infrastructure is equipped with advanced protective relays capable of detecting faults and de-energizing circuits within one-tenth of a second. Moreover, FTFM capable relays can be remotely activated by NV Energy's System Control. The ability to remotely enable and disable FTFM to respond to changing fire conditions reduces the burden on field personnel who would otherwise need to manually activate FTFM locally.

10. Q. WHAT ARE THE BENEFITS OF FTFM?

A. FTFM plays a critical role in wildfire prevention because electrical infrastructure is a known ignition source during extreme weather conditions. Even a minor delay in disconnecting power after a fault can result in arcing or sparking with the potential to cause an ignition, especially during fire weather conditions. FTFM addresses this risk by reducing the fault clearing time to nearly instantaneous, significantly reducing the propensity for arcing or sparking and minimizing the amount of hot particles. By reducing sparks from reaching dry vegetation or other objects, FTFM significantly reduces the likelihood of utility-caused wildfires.

Additionally, FTFM serves as a layer of safety as a measure that can be implemented prior to deploying Public Safety Outage Management ("PSOM"). While PSOM preemptively de-energizes portions of the grid in extreme fire weather conditions, FTFM allows the grid to remain energized while providing continuous protection by rapidly isolating faults. FTFM allows power to stay on in some situations when no faults have been detected while safeguarding against fire risk in real-time. By adding this additional operational measure, FTFM can be deployed as a safety measure in heightened risk conditions, deploying PSOM only when conditions become extreme.

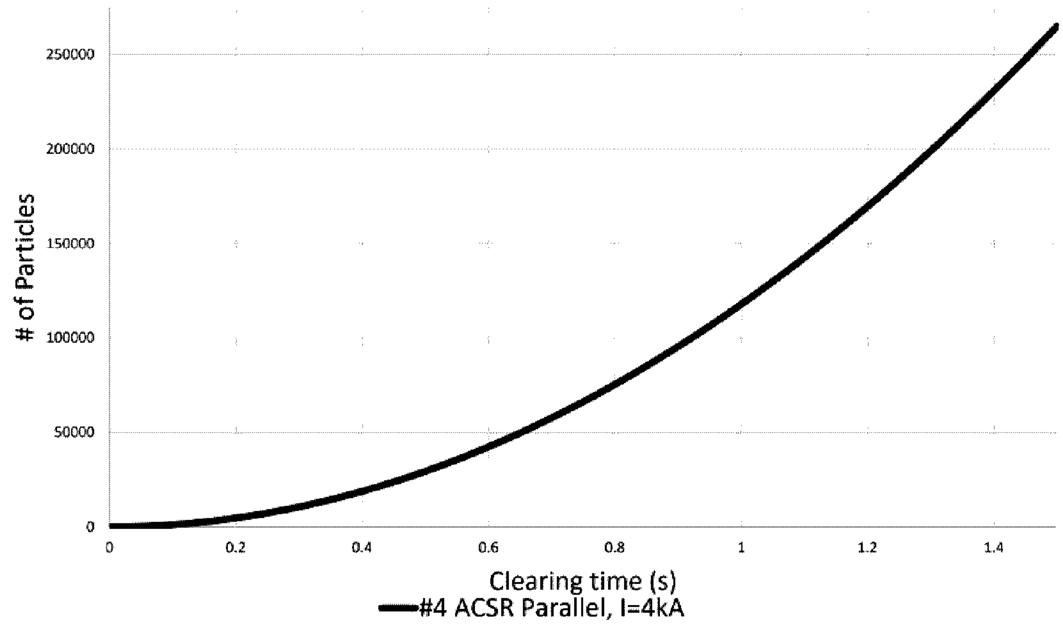
11. Q. DOES QUALITATIVE AND QUANTITATIVE RESEARCH INDICATE THAT FTFM IS A LEADING INDUSTRY PRACTICE AND HOW IS FTFM USED BY OTHER UTILITIES?

A. Yes. FTFM is aligned with leading industry practices across utilities in wildfire-prone areas. Utilities including PG&E, Southern California Edison ("SCE"), San Diego Gas & Electric ("SDG&E"), PacifiCorp, Avista, and BC Hydro have implemented fast trip relay settings to reduce wildfire risks. Utility solution details may vary by region, risk tolerance, and system topology. For example, PG&E uses fault clearing within one-tenth of a second based on extensive research showing that this faster fault clearing (within 0.1 second) drastically reduces the risk of fire ignitions due to electrical faults. PG&E also found that fire-causing hot particles exponentially increase with longer fault clearing times. SCE and SDG&E use fast trip settings like PG&E to balance safety coordination and reliability. PacifiCorp and Avista employ fast trip mode but may allow reclosing in lower-risk areas. BC Hydro tested fast trip mode on laterals using Siemens Fusesavers ("FS"), but typically uses longer fault clearing times, especially for phase faults.

Figure Icenhower-Direct-1 shows the exponential increase in high temperature particles based on longer fault clearing times based on PG&E's research.

Figure Icenhower-Direct-1

Increase in High Temperature Particles for Longer Fault Clearing Times



Source: **Exhibit Icenhower-Direct-2**, Assessment of How and Flaming Particles and Fire Risk from High Current Faults at p. 18.

12. Q. WHAT APPROACH DOES NV ENERGY USE FOR FTFM?

A. NV Energy follows PG&E's research-backed approach as it prioritizes safety in high-risk fire areas. Since deploying PG&E's equivalent of FTFM, called Enhanced Powerline Safety Settings ("EPSS"), across its entire service territory, PG&E has seen a 68 percent reduction in fire ignitions and a 99 percent reduction in fire size. By adopting 0.1 second fault clearing time, NV Energy aims to provide the same level of protection through these types of reductions to protect public safety. **Exhibit Icenhower-Direct-3** provides details of the PG&E program.

13. Q. HOW DOES FTFM SPECIFICALLY BENEFIT COMMUNITIES AND CUSTOMERS?

A. FTFM benefits communities and customers with increased fire safety during high-risk fire conditions. By detecting and isolating faults quickly, FTFM reduces the risk of utility-related wildfires to protect homes, communities, and people. Reducing the risk of wildfires also lowers the long-term costs associated with fire damage and infrastructure repairs.

14. Q. WHAT CUSTOMER IMPACTS MIGHT RESULT FROM FTFM?

A. The activation of FTFM during high-risk fire conditions may lead to an increase in service interruptions during high fire risk days. This is a result of adjusted system settings that are more sensitive to faults and minor disturbances, such as a branch briefly contacting a power line. Additionally, due to the shortened fault interruption time, bypassed time-based coordination between protective relays and/or fuses may result in outages over a larger footprint. For example, a fault on a fused lateral may cause the protection scheme at the substation to trip an entire circuit because the substation relay responds to the fault much faster than the fuse. While FTFM may result in more frequent outages, these protocols mitigate against the impacts of potentially devastating wildfires.

15. Q. HOW IS NV ENERGY MITIGATING THE IMPACTS OF FTFM?

A. NDPP has multiple programs that minimize reliability impacts of FTFM in the longer term that include:

1. <u>Vegetation Management</u>. NV Energy actively trims trees and clears vegetation around power lines to reduce the likelihood of faults caused by vegetation contact.
2. <u>Distribution Protection</u>. NV Energy is installing TripSavers and fault indicators on distribution circuits. TripSavers can operate in an instantaneous trip mode,

coordinating with the FTFM relays to isolate lateral faults without de-energizing the entire circuit. This approach reduces outage impacts and accelerates restoration by reducing the length of circuit requiring an inspection before re-energization. Fault indicators help pinpoint fault locations, enabling field personnel to identify and resolve issues more quickly, shortening outage durations. Ongoing coordination studies to assure protection schemes operate as designed, or undergo optimized redesign, helps mitigate the impacts of FTFM.

3. Covered Conductor. Insulated wires, known as covered conductors, are used to mitigate fault risks by reducing the chance of bare wire coming into contact with nearby branches and/or vegetation.
4. Pole Replacements and Infrastructure Upgrades. Replacing wood poles with steel or concrete poles mitigates faults by strengthening infrastructure against high winds and extreme conditions. This strengthened infrastructure will reduce the likelihood of a fault occurring, as well as reduce fire risk.

16. Q. PLEASE EXPLAIN THE RESTORATION PROCESS AFTER FTFM.

A. If FTFM is active and a circuit trips due to a fault, the restoration process is designed to ensure that the circuit can be safely re-energized with consideration for fire safety and operational efficiency. The restoration process is conducted by troubleshooters as follows:

1. Line Inspection. Following the activation of FTFM, the first step is to dispatch field personnel to physically inspect the de-energized line. The purpose of this inspection is to identify any hazards that may have caused the fault, such as downed power lines, fallen tree branches, or damaged equipment. This ensures that any potential fire risks are addressed before restoration can proceed.

2. Repairs and Hazard Removal. If damage or hazards are identified, a line crew is promptly dispatched to perform the necessary repairs. This may involve repairing downed lines, removing tree branches and debris, or replacing damaged equipment. Ensuring that identified hazards are addressed is critical to avoiding further faults or fire ignitions when the line is restored.
3. Clearance and Re-energization. Once the line has been inspected and any necessary repairs have been completed, the circuit is cleared for re-energization. The control center remotely restores power to the affected customers once it is confirmed that no immediate fire risk exists.
4. Customer Notifications. NV Energy provides real-time updates to customers during outages, including estimated restoration times.

The inspection and repair process is essential to preventing the risk of wildfires. Although outage duration may be longer, underlying issues are resolved before power is restored as a safety precaution. The seven additional troubleshooter positions identified as part of the labor resource plan sponsored by NV Energy witness Ms. Howard will promote faster inspection, repair, and re-energization times as a result of the deployment of FTFM.

17. Q. ARE THERE ALTERNATIVES TO FTFM?

A. An alternative to FTFM is to maintain the standard Fire Season No-Reclose Mode settings. However, this approach carries the risk of depriving customers and communities of more sensitive protection settings during severe weather. Without FTFM, NV Energy may be unable to effectively reduce wildfire risk further and could lag the industry in implementing a proven risk mitigation strategy.

Another alternative is to use PSOM, which requires de-energization of the power grid. As compared to a PSOM, FTFM leaves the grid energized and only trips when a fault condition is detected.

18. Q. PLEASE SUMMARIZE THE IMPORTANCE OF FTFM.

A. FTFM is a practical operations approach that offers additional protection compared to Fire Season No-Reclose Mode and provides an alternative to PSOM in less critical weather conditions. FTFM delivers immediate and effective protection against utility-caused wildfires by responding to faults almost instantaneously, significantly reducing the likelihood of sparks igniting wildfires. FTFM balances the need for rapid fault isolation with minimal disruption to customer service, positioning FTFM as a pragmatic solution for addressing wildfire risks in the short term during the high danger wildfire conditions.

II. <u>DISTRIBUTION AUTOMATION</u>

19. Q. PLEASE EXPLAIN THE NDPP-RELATED DISTRIBUTION AUTOMATION RESOURCES NV ENERGY IS REQUESTING AND WHY THOSE RESOURCES ARE NECESSARY.

A. As detailed in the Prepared Direct Testimony of NV Energy witness Ms. Howard, the Companies are requesting approval to hire NDPP-related distribution automation personnel to coordinate, maintain, and expand the Companies' efforts to operate new fire mitigation technology and equipment, while reducing the reliability impact to customers. The distribution automation initiative will address NDPP emergency response impacts by enabling "smart" devices that will be used to automatically control the system and reduce the number of customers and duration of NDPP-related outages. Ms. Howard explains how the Companies will use distribution automation engineers and what that team will be responsible for, while my testimony speaks to the importance of distribution automation personnel from an engineering perspective in the context of NDPP and in the deployment of certain enhanced fire season protocols.

20. Q. ARE THERE TRADEOFFS BETWEEN GRID RESILIENCE FOR NATURAL DISASTER MITIGATION AND RELIABILITY AND HOW DOES DISTRIBUTION AUTOMATION IMPACT THESE TRADEOFFS?

A. Yes. Some of the grid resilience operating practices, such as the fire season protocols, include equipment and policies to either reactively or proactively de-energize the grid.[1] These de-energization approaches can impact reliability, but the tradeoff is increased resilience and increased public safety protection. Distribution automation impacts these tradeoffs by adding intelligent technology to the distribution system to reduce outages caused by NDPP-related activities.

21. Q. WHAT IS THE ROLE OF DISTRIBUTION AUTOMATION NORMALLY AND HOW WILL DISTRIBUTION AUTOMATION BE USED TO SUPPORT RISK MITIGATION EFFORTS LIKE NDPP?

A. In the current configuration, the distribution regional engineers are primarily focused on operational performance, the review of protection scheme operations when a circuit is field switched into a different configuration, responses to failed protective devices, and limited implementation of distribution automation. Regional engineers are already fully occupied with these day-to-day operations and cannot always proactively perform in-depth analysis or implement

[1] Proactive de-energization, like PSOM and the emergency de-energization policy, results from personnel-driven decisions and actions based on predefined safety criteria. Reactive de-energization, such as no-reclose and FTFM, is equipment driven when a fault condition is detected.

automation technologies. These regional engineers oversee distribution protection, including selecting locations and types of automatically operating devices such as reclosers, TripSavers, and fuses.

In the context of risk mitigation like NDPP, distribution automation can underpin all equipment driven programs for natural disaster risk mitigation as an effective means to balance system resilience with reliability. Specifically, the distribution automation team will perform engineering studies and system analysis to assess the impact of potential proactive or reactive de-energization, identifying where activations may cause larger (or longer duration) system outages than necessary. Deploying automation technologies can reduce the reliability effects of de-energization activities. The NDPP distribution automation team will also be responsible for the field installation and maintenance of installed automated and protective devices. These activities include coordination to fire season settings, enabling remote capability to trigger seasonal or FTFM settings when heightened fire risk conditions escalate.

22. Q. HOW WOULD AN NDPP-FOCUSED DISTRIBUTION AUTOMATION TEAM REDUCE NATURAL DISASTER RISK?

A. NDPP changes the need for distribution automation, in that reducing wildfire risk will rely more heavily on remote devices to operate quickly and correctly. The distribution automation engineers dedicated to NDPP would proactively select locations and types of automatically operating protective devices such as reclosers, TripSavers, and fuses, even as these technologies continue to rapidly evolve. A dedicated department overseeing the automation and protection of the distribution network holistically would reduce risk by:

- <u>Modernizing outmoded coordination on distribution circuits</u>**:** Many distribution circuit computer models and protective device settings are not reviewed or updated on a regular cadence. Furthermore, settings were prepared prior to the NDPP, with considerable tripping delays between devices to ensure coordination and reliability. However, it is possible to use optimization studies for smaller delays under Fire Season No-Reclose Mode to preserve the reduced fire ignition risk while maintaining coordination for reliability. Additionally, the distribution automation team would prioritize circuits for distribution automation technologies and collaborate with companion technologies and complementary infrastructure, such as telecommunications, for successful implementation.
- <u>Address the growing need for automation technology</u>: With more frequent and severe wildfires, modern distribution automation schemes, such as falling conductor detection, Fault Location, Isolation, and Service Restoration ("FLISR") automation, and sensor technologies, have the potential to significantly reduce the impacts of proactive and reactive de-energization approaches to reliability. Distribution automation experts can design the distribution network to automatically respond to outages by detecting where a fault is located and then self-heal by restoring parts of the network that are still healthy during severe natural disasters. This is helpful during wildfires and for other natural disaster conditions like heavy snowstorms with wet snow taking down sections of the distribution grid.

23. Q. PLEASE EXPLAIN HOW A NDPP-PRIORITIZED DISTRIBUTION AUTOMATION TEAM CAN BOTH MITIGATE THE RELIABILITY IMPACTS OF PROTECTION SCHEMES AND REDUCE NATURAL DISASTER RISK.

A. A NDPP distribution automation department would focus on both strategically reducing wildfire risks and improving system reliability in the face of increasing frequency and severity of natural disasters that include wildfires, earthquakes, winter storms, flooding, and severe winds. Optimally performing distribution protection and automation schemes designed and deployed by NDPP-dedicated distribution automation engineers can not only minimize grid downtime, but also reduce risk and improve resilience.

The following examples represent possible functions and technologies a NDPP-prioritized distribution automation team may deploy.

- Proactive distribution protection coordination for wildfire mitigation: The team will periodically field verify protective devices on distribution circuits and conduct in-depth distribution device coordination studies on prioritized circuits within the fire Tiers. This has the potential to reduce fault clearing times during Fire Season No-Reclose Mode, optimize protection settings, and mitigate wildfire ignition risks.
- Standardized cadence for holistic study and review: The distribution automation team will establish regular review cycles of NDPP protection and automation technologies, and consider all contributing factors holistically for strategic placement of new line protective and automation devices to both promote reliability and reduce wildfire risks. The distribution automation team

also would keep current with rapidly evolving industry practices and technologies.

- <u>Proactive deployment of distribution automation technologies to promote reliability</u>: The distribution automation team will stay current with industry best practices and distribution automation technologies and implement technologies such as fault indicators, FLISR, and distribution falling conductor detection to automatically isolate faults and enable the grid to self-heal to restore customers on healthy parts of the network.

24. Q. HOW ELSE CAN DISTRIBUTION AUTOMATION SUPPORT GRID RESILIENCE AND RELIABILITY?

A. Distribution automation may collaborate with Transmission Planning or Distribution Planning to select strategic locations fed by radial transmission or distribution lines to deploy technologies such as microgrids to reduce the impacts of large-scale or long-term outages caused by the deployment of fire season protocols.

25. Q. WHAT IS THE LONGER TERM OUTLOOK FOR DISTRIBUTION AUTOMATION CONTRIBUTIONS TO RISK MITIGATION EFFORTS LIKE NDPP?

A. Distribution automation will develop and implement a technical long range grid resilience plan that proposes protective and automation technologies to reduce wildfire ignition risks and improve the grid's ability to automatically respond and self-heal to natural disasters and outages. This includes a holistic review all NDPP programs with the various program leads and experts to ensure that all programs complement and coordinate with each other. Examples of these efforts include support for grid hardening programs by ensuring protective studies are performed and automation technologies deployed on covered conductor projects.

26. Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT ICENHOWER-DIRECT-1

STATEMENT OF QUALIFICATIONS OF

Joshua D. Icenhower
Manager, System Protection Engineering
NV Energy
1 Ohm Pl, Reno NV, 89502
(775) 233-0486 joshua.icenhower@nvenergy.com

Mr. Icenhower has been an employee of NV Energy for five years and has over a decade of experience in the power industry, specializing in system protection, substation operations and maintenance, and hydrogeneration and substation design. His focus has been on the safety and reliability of the electric grid, with direct oversight of critical infrastructure and advanced protection technologies. He leads teams responsible for implementing system protection strategies and ensuring compliance with NERC and CIP standards for over 200 substations. His expertise has played a key role in enhancing grid resilience and improving fire safety through the development and deployment of solutions like fast trip fire mode, which is designed to mitigate fire risks in high-risk areas.

Professional Experience

Manager, System Protection Engineering – NV Energy, Reno, NV ▪ 2021 – present

- Lead the system protection engineering team, overseeing the protection and control systems of over 200 substations across northern Nevada to ensure safe and reliable grid operations.
- Develop and implement protection schemes that safeguard critical infrastructure particularly those designed to address fire hazards in high-risk regions, including fast trip fire mode technology.
- Ensure compliance with operational standards and NERC/CIP regulatory requirements, monitoring relay performance to react effectively to faults, power swings, and system disturbances to maintain grid reliability.
- Spearheaded the modernization of relay systems, improving remote enablement of protection schemes and ensuring that system control can respond quickly to daily fire risk conditions.
- Monitor and analyze relay performance, ensuring the proper function of protection systems during faults, power fluctuations, and other grid events, making necessary adjustments to improve grid reliability.

Senior Substation Engineer – NV Energy, Reno, NV ▪ 2019 – 2021

- Developed a condition-based maintenance program for more than 200 substations, leveraging data and key performance indicators to prioritize repairs and optimize equipment reliability.
- Monitored equipment performance through key performance indicators (KPIs) to proactively identify and address potential issues, reducing downtime and minimizing the risk of equipment failure.
- Coordinated with operations field teams to ensure that all substation equipment was maintained according to company maintenance and NERC compliance standards.

Senior Electrical Engineer – US Bureau of Reclamation, Sacramento, NV ▪ 2017 – 2019

- Designed and commissioned hydroelectric projects, including generator protection relay upgrades.
- Provided technical oversight during the commissioning of generator protection systems, created test plans, and worked closely with field crews during construction and commissioning.

Electrical Project Engineer – ***Construction Innovations, Sacramento, CA ▪ 2016 – 2017***

- Managed the engineering design, manufacturing, and construction of renewable energy interconnection substations, overseeing all phases of the project lifecycle from initial design to final commissioning.
- Coordinated cross-functional teams to design, construct, and commission over 8 interconnection substations, generating approximately $18M in revenue.
- Streamlined construction processes, improving efficiency and reducing field installation time by 75% through innovative pre-fabrication and modular designs.

Hydro Design Engineer II – ***Black & Veatch, Sacramento, CA ▪ 2014– 2016***

- Designed and commissioned hydroelectric projects including generator governor and exciter upgrades, medium-voltage switchgear, and protection relay systems, ensuring compliance with industry standards.
- Conducted system studies including arc flash studies to ensure that protection systems reacted promptly to faults to ensure personnel safety.
- Collaborated with project managers and engineers from other disciplines to ensure design alignment with overall project goals and timelines.

Education and Certifications

Bachelor of Science in Electrical and Electronics Engineering – Power Systems

California State University Sacramento, 2014

Professional Licenses

Professional Engineer (PE) - Electrical and Computer: Power

- NV License No: 029559
- CA License No: E 21977

EXHIBIT ICENHOWER-DIRECT-2

Assessment of Hot and Flaming Particles and Fire Risk from High Current Faults

Brendan P. Dooher, Ph.D., Principal, Wyvernn

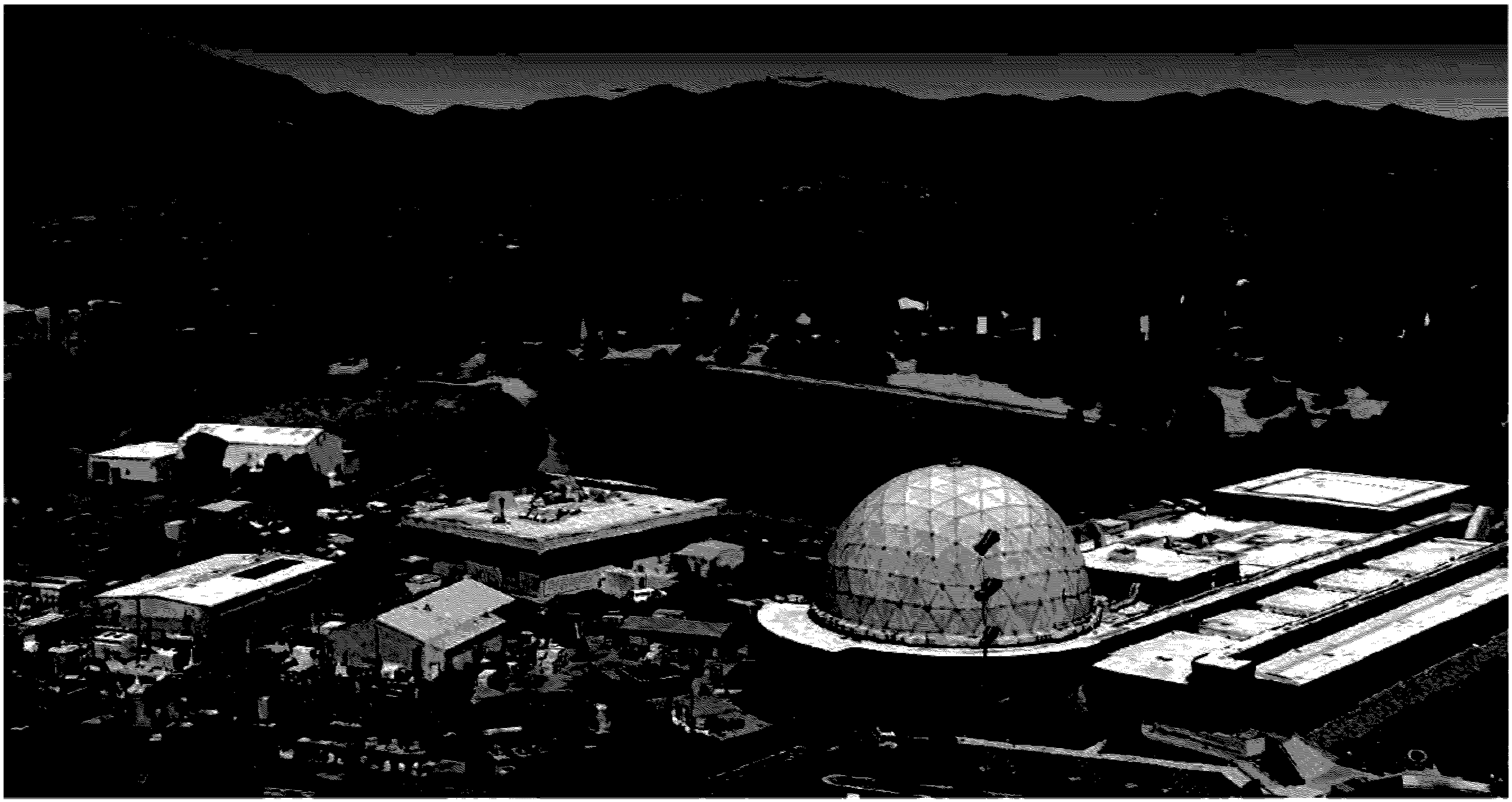
Robbie James, Senior Protection Engineer, System Protection, PG&E

Scott Hayes, Principal Protection Engineer, System Protection, PG&E

Ruth Leung, Senior Electrical Engineer, Applied Technology Services, PG&E

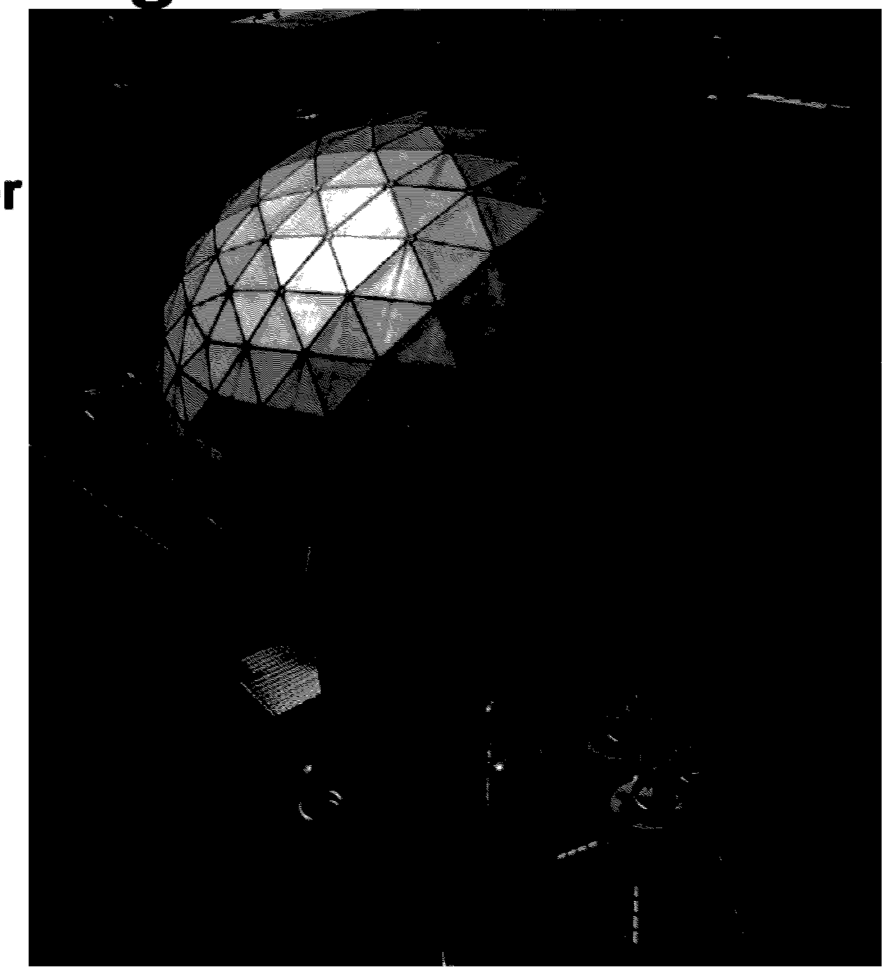
Michael Antiniw, Expert Electrical Engineer , Applied Technology Services, PG&E

The PG&E Applied Technology Services (ATS) Technology Center (San Ramon, CA)



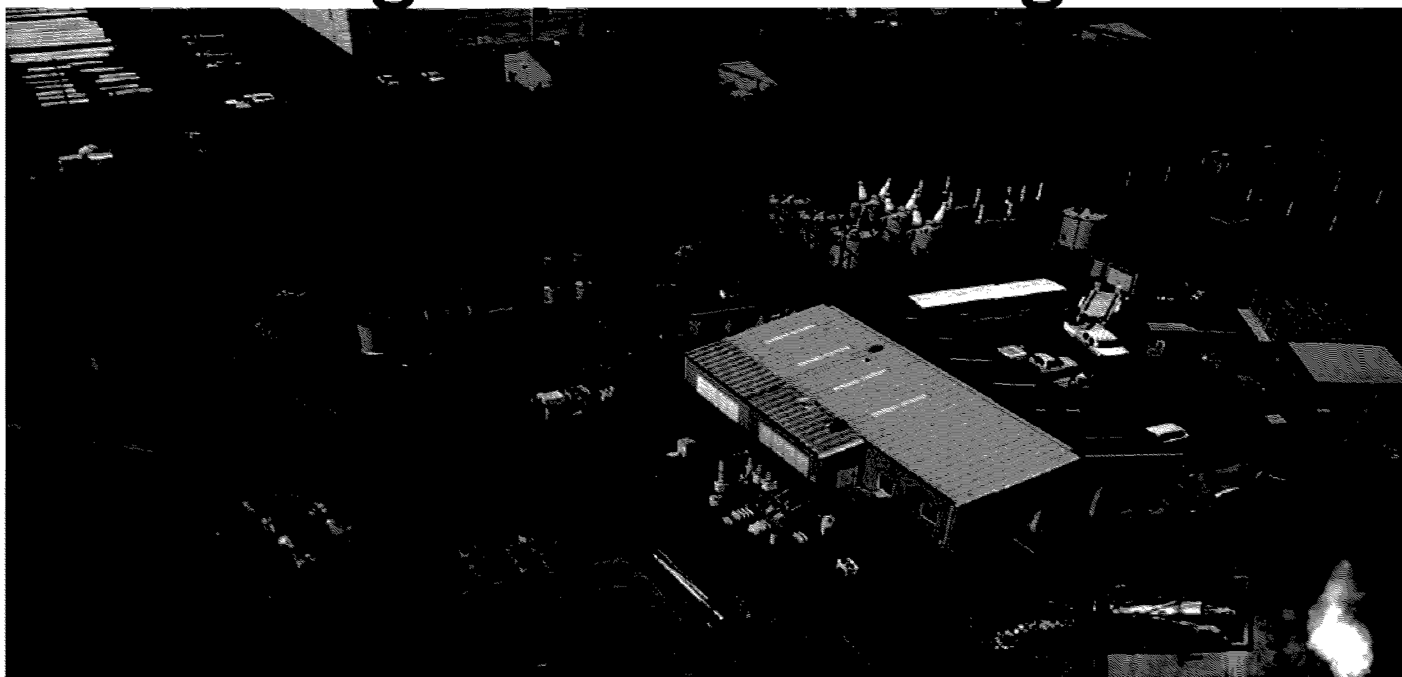
PG&E ATS High Voltage Testing Dome

- Indoor testing facility can create a voltage level up to 720,000 volts with full fog chamber capability.
- Equipment and Dielectric testing.
- Event recreation and incident investigations.
- This facility has been featured on the Discovery Channel program "Mythbusters".



PG&E ATS High Current Testing Yard

System Protection - Davis Erwin, Mike Jensen, Scott Hayes, Robbie James, Mark Imperatrice, Matt Johnson, and Hai Le



Fault Testing at ATS sponsored by PG&E System Protection.

ATS – Brendan Dooher, Ruth Leung, Michael Antiniw, Gene Hanes, and Ryan Sparacino

- **Outdoor Test Substation with capability to create up to 80,000 Amperes.**
- **Full power utility equipment testing.**
- **Arc Flash clothing and equipment testing.**

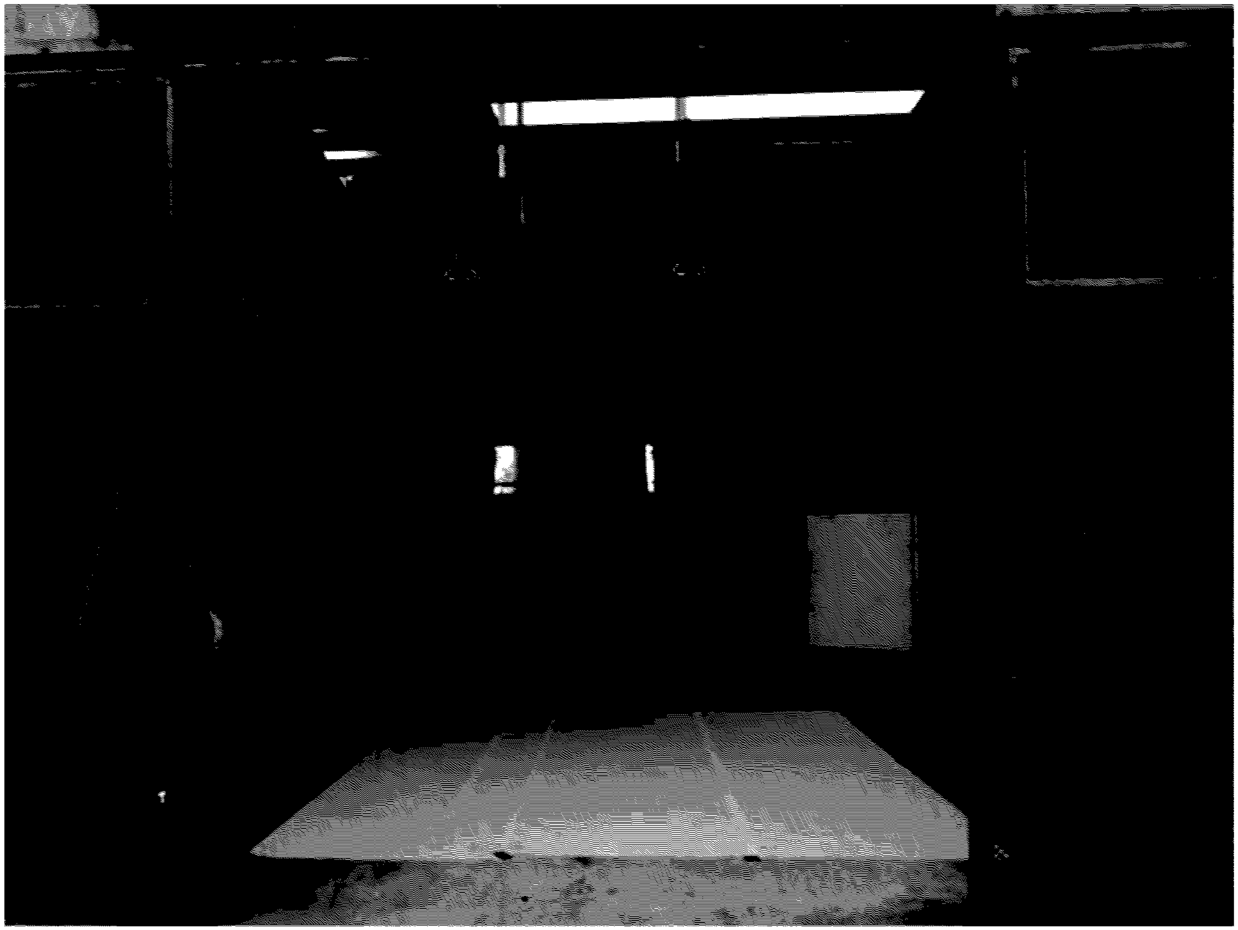
Testing and Results

- This testing was fundamental research and has not been performed at this level in the industry.
- The resulting 65-page report is dense and complex.
- Faults are random and chaotic processes, so significant variation occurs.
- ATS testing was conducted over a 3-week period, but multiple faults under the same conditions were not tested.
- Results and formulas developed by ATS are not a measure of absolute risk but are a measure of the relative risk of increasing or decreasing specific values.

Testing at two different elevations (Lift and Cage)

- Cage Tests – approximately 10 feet (indicative of flash zone)
- Lift Tests – Forty feet (indicative of final fall zone from conductors in the field)
- Tests were performed at approximate amperage levels of 1000, 4000, and 7000 amps
  - 1000, 4000, and 7000 amp tests were all performed in the Cage
  - Only 4000 amp tests were performed on the Lift
  - Combinations were only possible for 4000 amps
- Major test types were **“Parallel”** and **“Pigtail”** tests
- Conductors tested #4 ACSR, 397 MCM Al, 3/0 Cu,
- Structure impact using Angle Iron to 397 MCM AL
- Interrupt times were approximately 0.1, 0.25, 0.5, 1.0, and 1.5 s

Cage testing setup, PG&E ATS High Current Yard



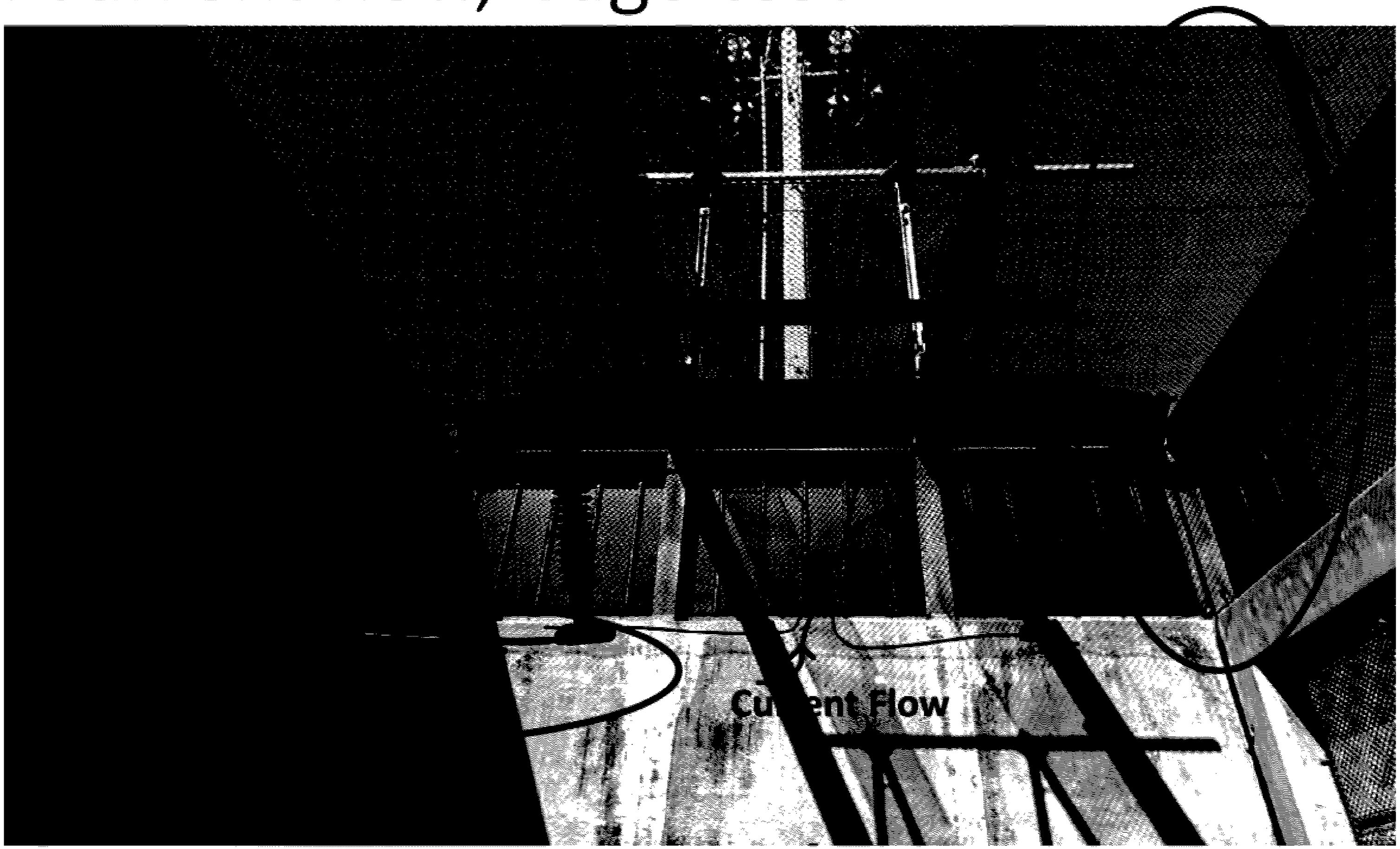
Overall view of "Cage" test setup.

Cage testing setup, PG&E ATS High Current Yard

Pigtail conductor configuration in "Cage" test.

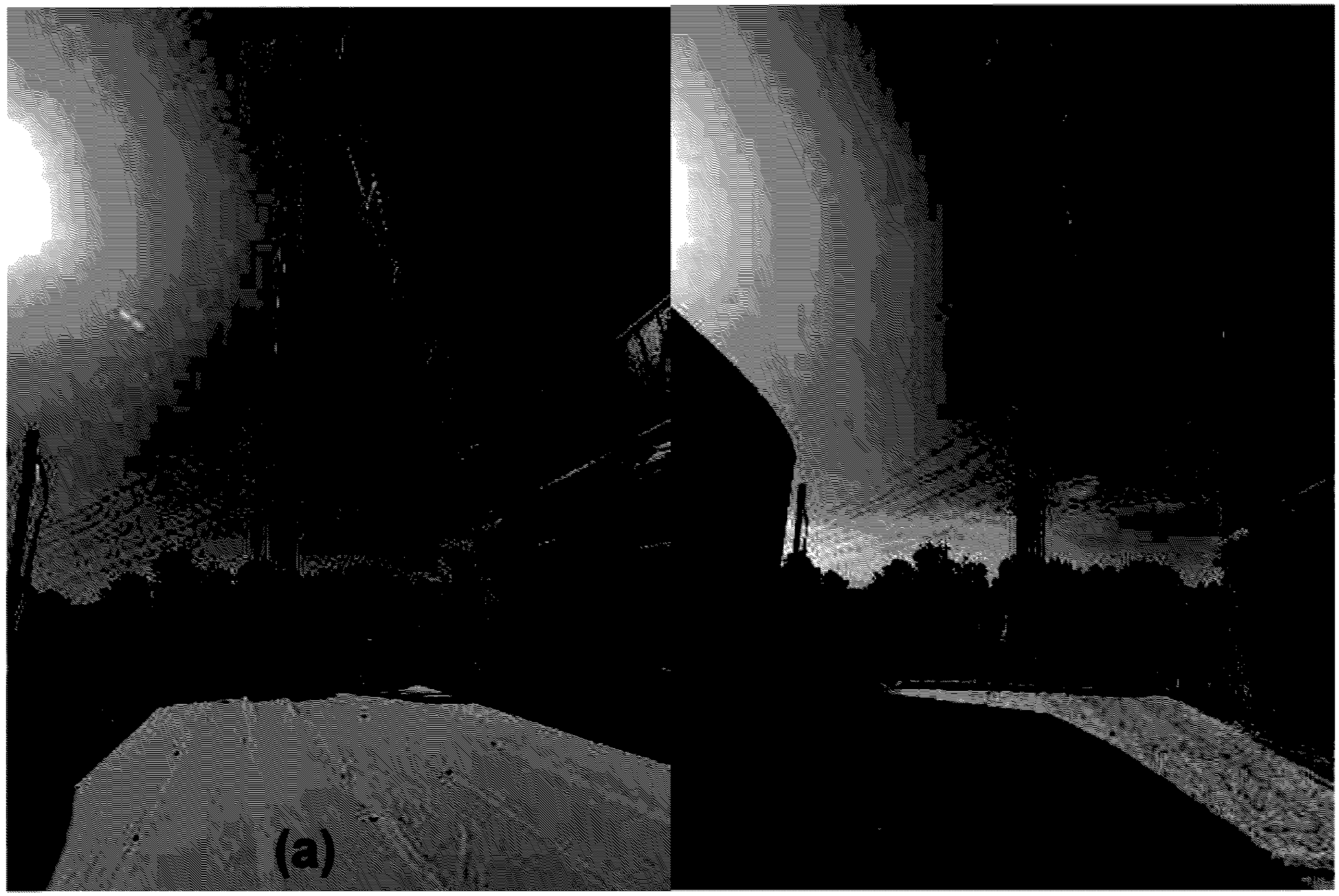
Parallel conductor configuration in "Cage" test.

Parallel Testing, magnetic forces configuration and current flow, Cage test



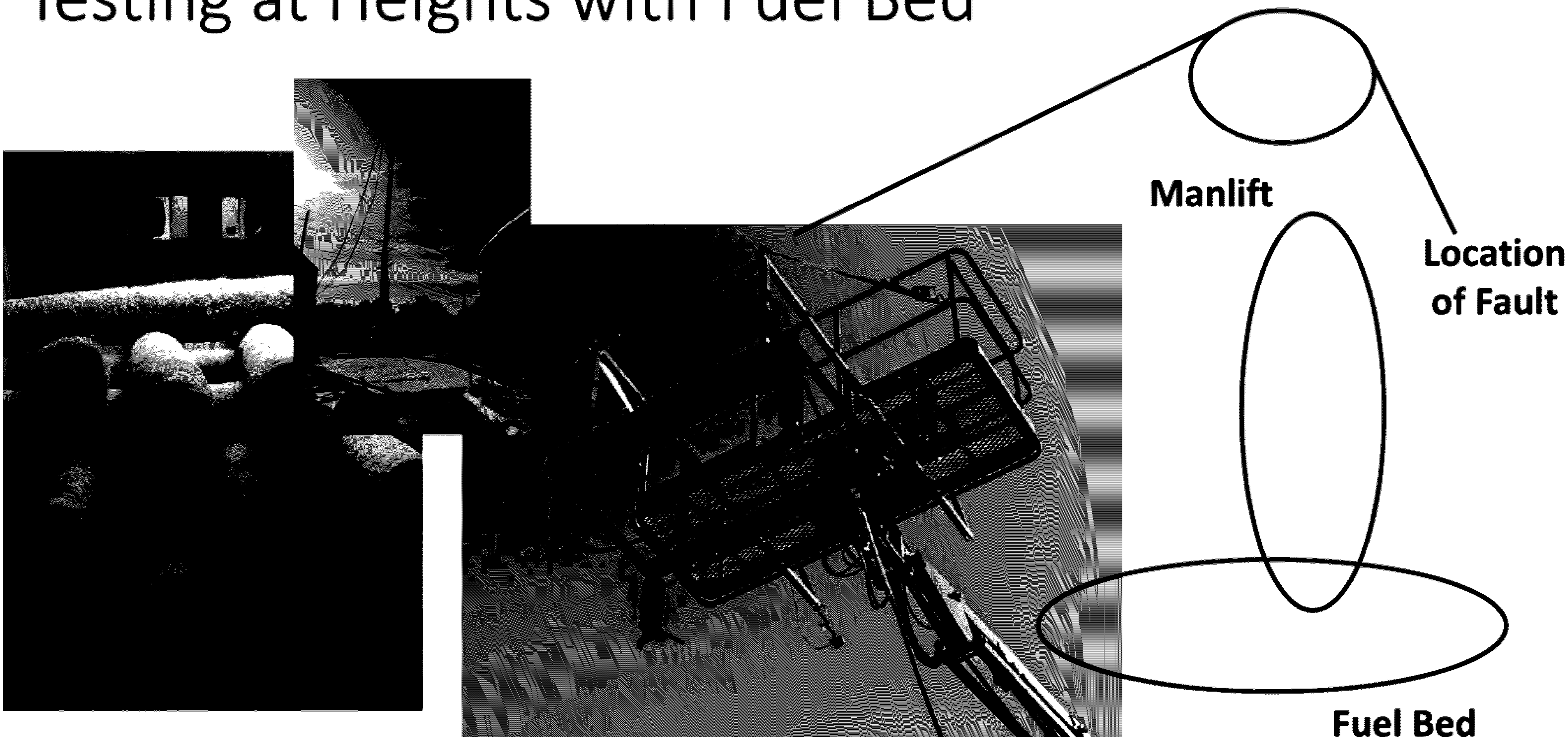
Lift testing setup at the PG&E ATS High Current

Lift test environment, showing location of FLIR Camera.



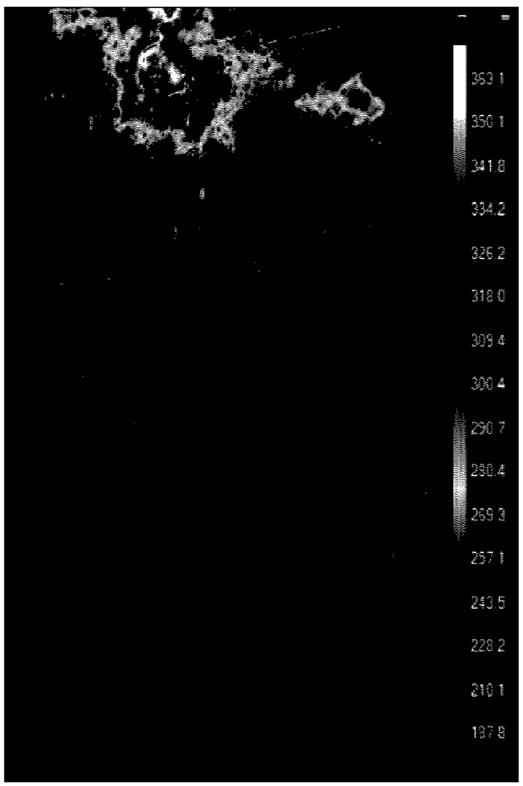
(a) kraft paper test bed (b) Cal-Fire approved test bed.

Testing at Heights with Fuel Bed

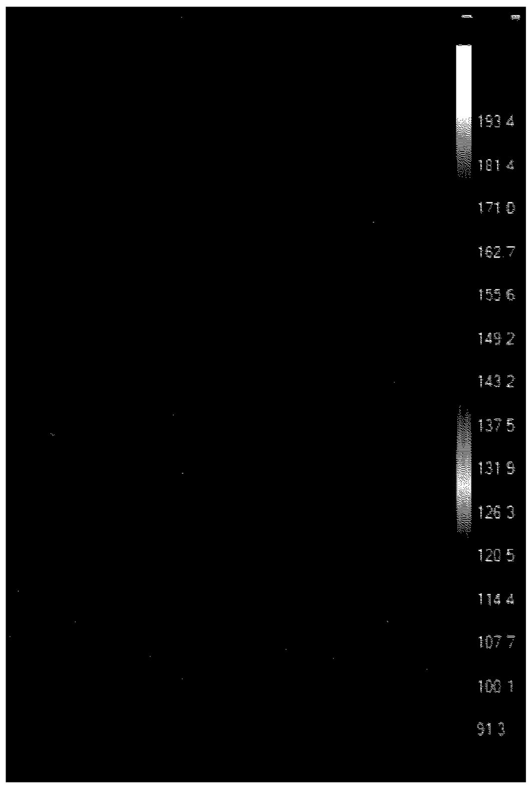


Held in climate controlled storage.

FLIR Camera and Data Analysis



Cage Test.



Lift Test.

FLIR camera used to track particle position/velocity/temperature.

Millions of particles being tracked on 148 separate tests (faults).

Data analysis to quantify fire risk for various factors:

- Tripping Time
- Fault Current
- Height above ground
- Conductor Material
- Conductor Geometry

Analysis of data

- As data evaluation effort continued, focus shifted to variables that would be of greater significance and usefulness to System Protection
  - Particle Count (dependent variable)
  - Fall distance
  - Conductor material type for #4 ACSR, 397 MCM Al, 3/0 Cu, and Angle Iron/MCM AL
  - Fault type (Parallel or Pigtail)
  - Interrupt time (0.1, 0.25, 0.5, 1.0, and 1.5 s)
  - Line amperage (1000, 4000, and 7000 amps)

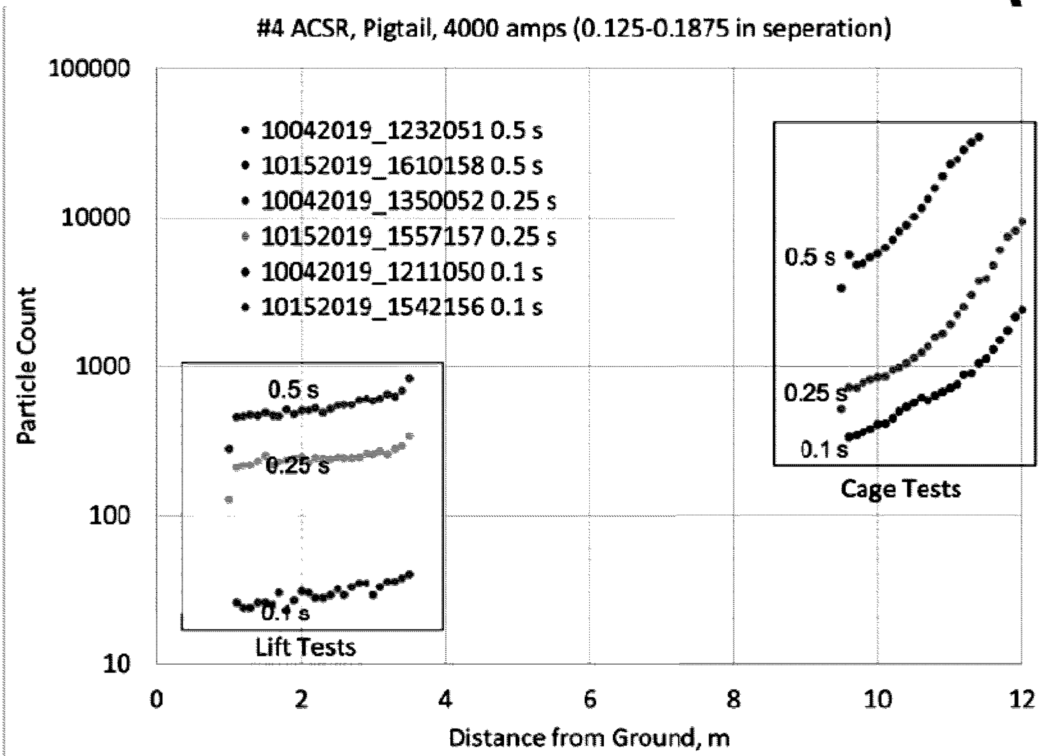
Tests were found to be able to be combined for 4000 amps ONLY (due to their only being lift data for 4000 amps)

- When similar attributes were combined (parallel/pigtail, copper, ACSR, MCM and interrupt times) Cage and Lift results tended to fall on the same curve lines

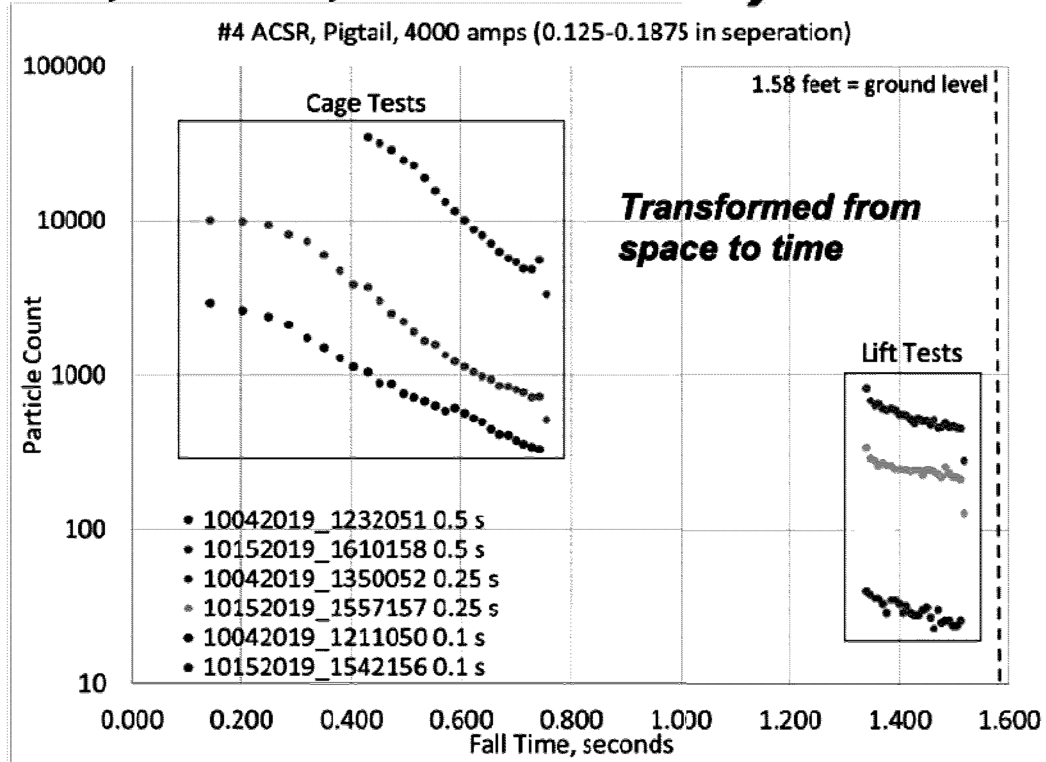
Analysis of data

- Particle points that were analyzed included 7.5 million points tracked over 75,000 FLIR camera IR images
- Temperature ranges for temperatures differed across the two tests, restricting direct one-to-one comparison (the newest FLIRs that don’t have that limitation were not available for rent)
  - Cage FLIR temperatures ranged from 150 C to 350 C – any particle below 150 C “vanishes” from the FLIR view field
  - Lift FLIR temperatures ranged from 80 C to 230 C – any particle above 200 C are saturated but visible within the FLIR view field

Particle Count for six different fault tests, #4 ACSR, Pigtail Configuration, and three different fault times (0.1, 0.25, and 0.5 s).



Vs. Distance from Ground (m)



Vs. Fall Time (seconds)

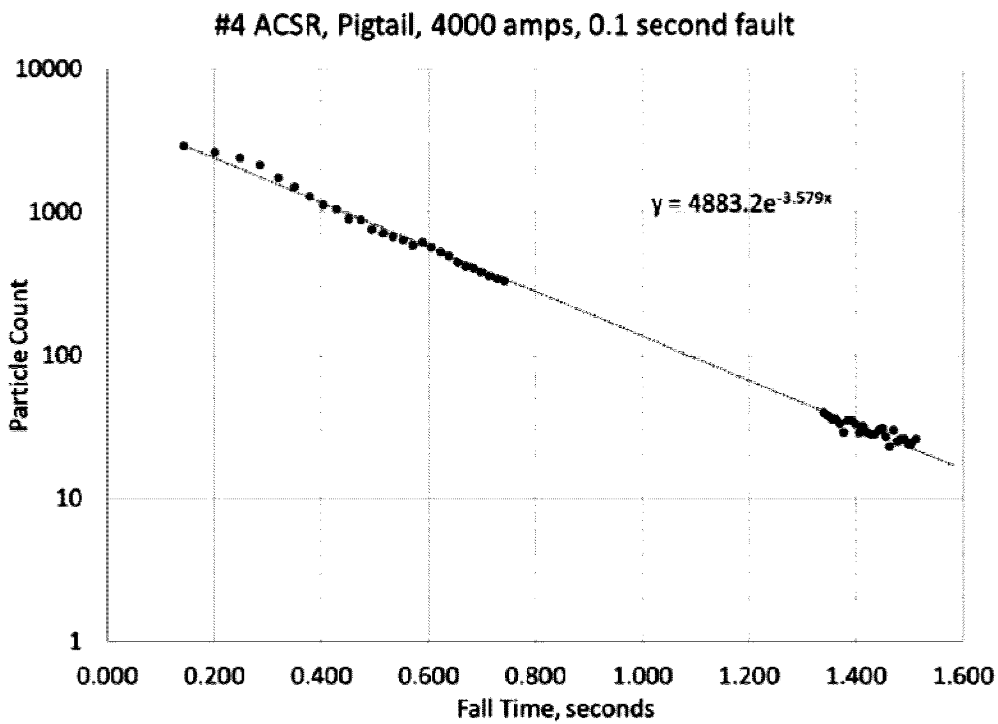
Data transformation

- Data is assumed to fall at acceleration of gravity
  - No buoyancy due to heating is assumed to occur (this is often assumed in theoretical particle fall calculations, and introduces some uncertainty to the overall data)
- Lift test occurred only at 4000 amps ONLY and therefore could only be combined for that amperage
- When similar attributes were combined (parallel/pigtail, copper, ACSR, MCM and interrupt times) Cage and Lift results tended to approximately fall on the same exponential curve lines
- Each curve then fell out as a single equation by material type of the form:

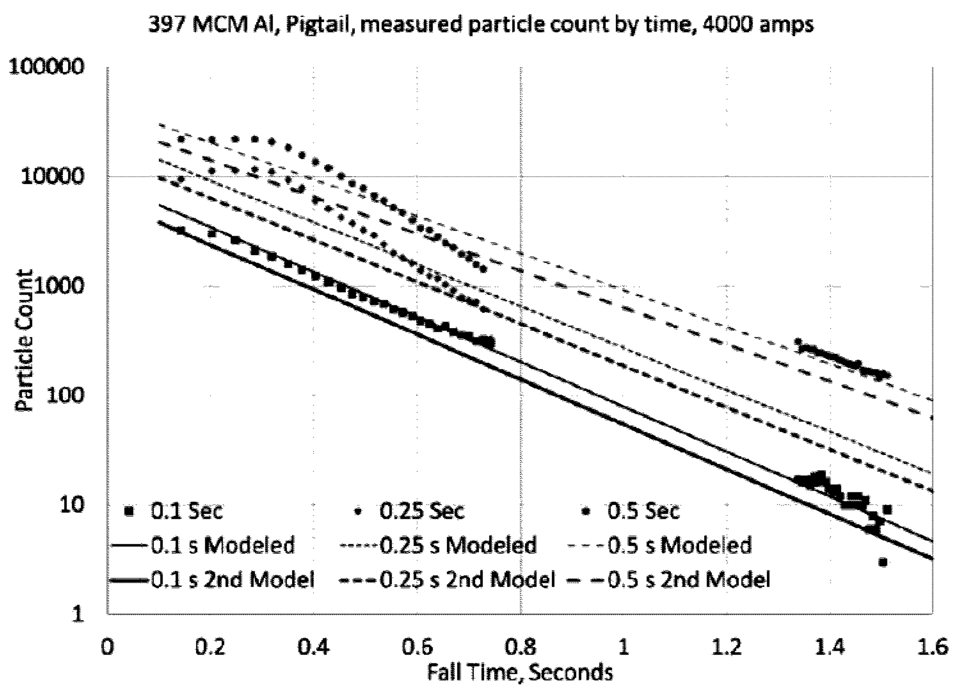
$$PartCount(t) = A^2 f^2 \exp(-\tau t)$$

- $\boldsymbol{\tau}$ is a time constant (the slope), $\boldsymbol{t}$ is fall time from particle production, $\boldsymbol{f}$ is interrupt time, and A is based on amperage

Modeling the results

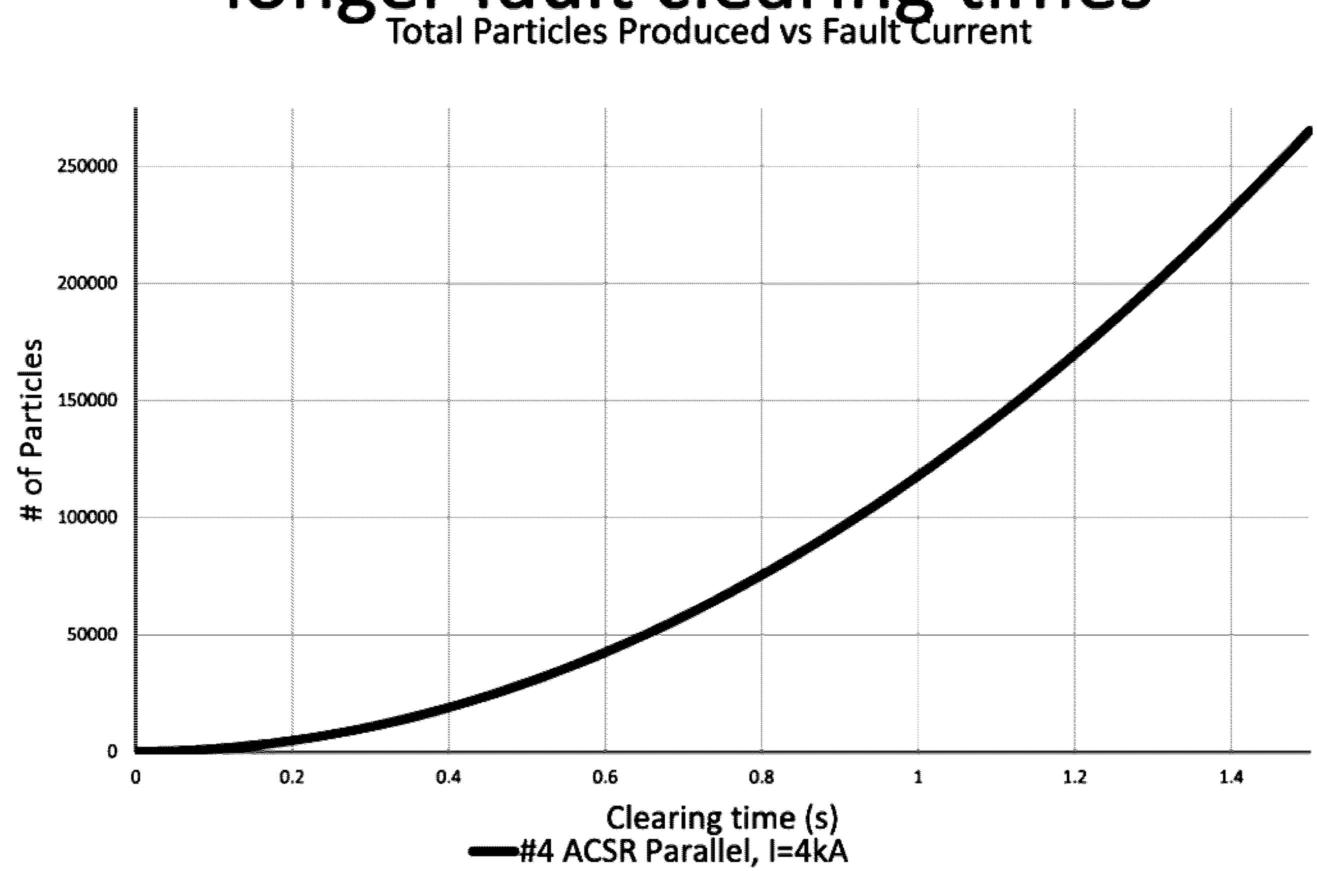


Particle Count vs. Fall Time (seconds) for the Cage and Lift tests combined, 0.1 second fault time, for #4 ACSR, Pigtail Configuration



Particle Count vs. Fall Time (seconds) for 397 MCM Al, Pigtail Configuration, with initial model (as a function of fault time, f) and 2nd model (as a function of fault time, f, and current, I)

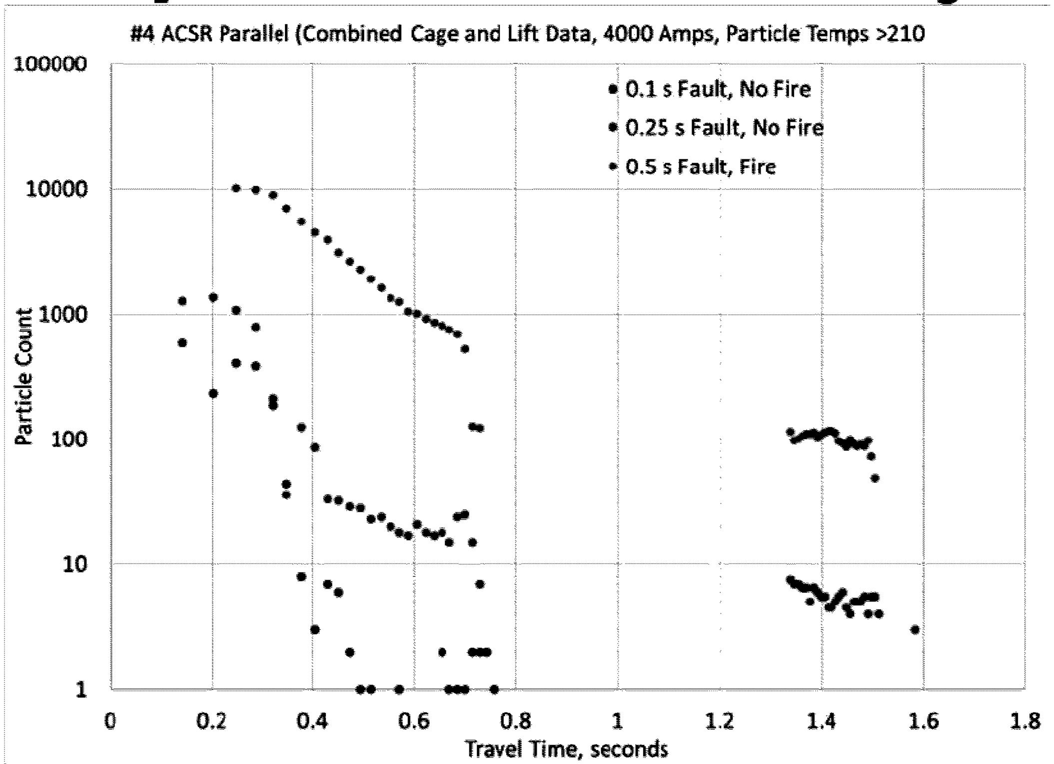
Large increase in high temperature particles for longer fault clearing times



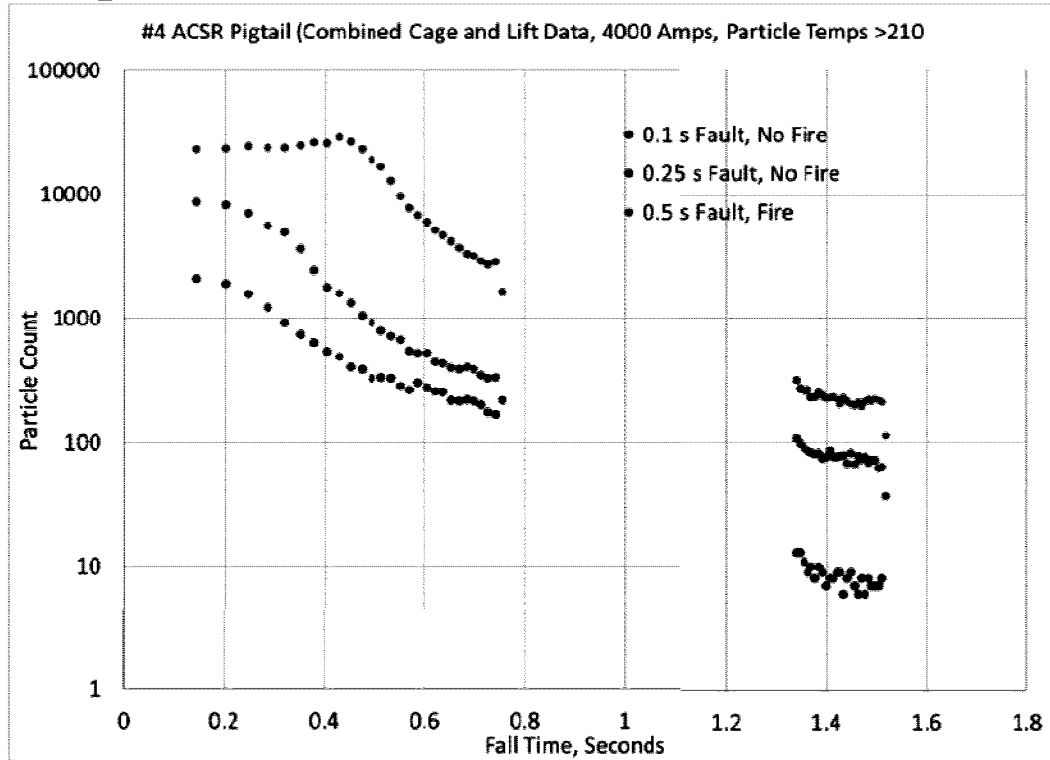
One part of the study focuses on two main dependent variables

- Total particle counts by time; and
- Particles counts exceeding ignition temperature by time
- Why these two dependent variables?
  - It was determined that particle count and particle temperatures that exceeded ignition temperatures appeared to be among the most valuable dependent variables due to their usefulness in determining particle fire risk
  - Knowable inputs are line current, fault interrupt time, and conductor type (also wind speed)
    - Configurations such as pigtails are currently being looked for in the field to place controls on them
    - Parallel line slapping produces less particles for a given current, conductor, and interrupt time
  - Controllable inputs are fault interrupt time and control of area where particles may blow (based on knowledge of fall time and particle count)
- ***Fire*** or ***No Fire*** as a result

Particle Count vs. Fall Time (seconds) for #4 ACSR, 4000 Amp combined tests, particle counts only for particles >210 C.



Parallel Configuration



Pigtail Configuration

Resultant Fires Observed (Fires/No Fires) 4000 amps, Kraft paper or Cal-Fire Test Bed

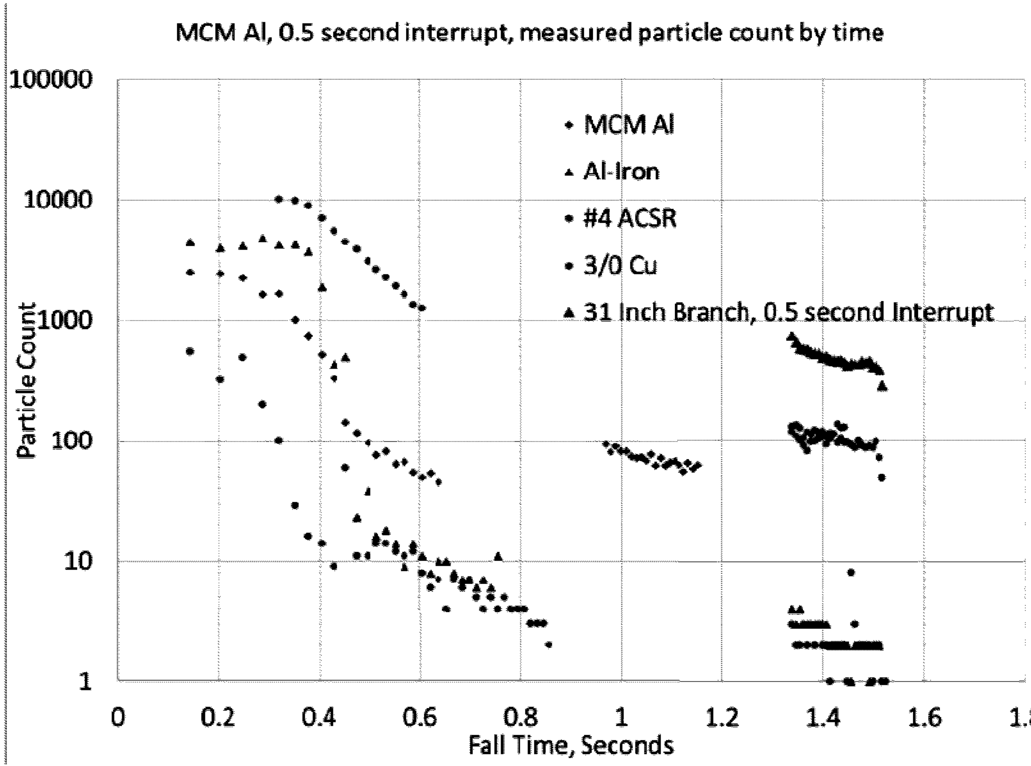
Lift tests

Conductor	Configuration	0.1 s	0.25 s	0.5 s	1.0 s
397 MCM Al	Parallel	No Fire	No Fire	No Fire	No Fire
	Pigtail	No Fire	Fire	Fire	Fire
#4 ACSR	Parallel	No Fire	N/A	Fire	Fire
	Pigtail	No Fire	Fire	Fire	N/A
3/0 Cu	Parallel	No Fire	N/A	No Fire	No Fire
	Pigtail	No Fire	No Fire	No Fire	Fire
Angle Iron-397 MCM AL	Parallel	No Fire	N/A	No Fire	Fire
	Pigtail	No Fire	N/A	Fire	Fire
Angle Iron - Steel Armor Rod	Pigtail	No Fire	N/A	No Fire	Fire

Cage tests

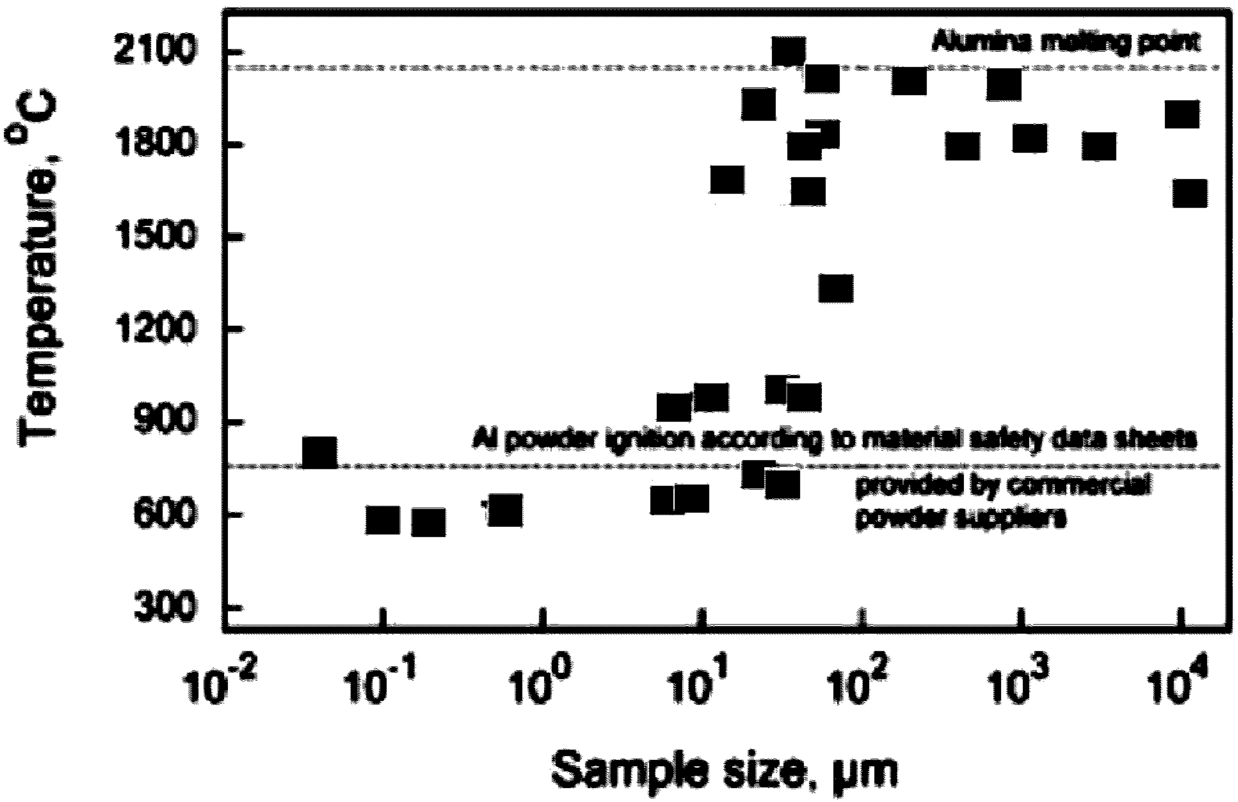
Conductor	Configuration	0.1 s	0.25 s	0.5 s	1.0 s
397 MCM Al	Parallel	No Fire	N/A	No Fire	No Fire
	Pigtail	No Fire	N/A	Fire	Fire
#4 ACSR	Parallel	No Fire	No Fire	Fire	N/A
	Pigtail	No Fire	No Fire	Fire	Fire
3/0 Cu	Parallel	No Fire	N/A	No Fire	Fire
	Pigtail	Fire	Fire	Fire	Fire
Angle Iron-397 MCM AL	Parallel	No Fire	N/A	No Fire	Fire
	Pigtail	N/A	N/A	N/A	N/A

Particle Count vs. Fall Time (seconds) for MCM A, #4 ACSR, 3/0 Cu, and Al-Iron, as well as 31 inch branch, 0.5 second Fault time, 4000 Amp combined tests



Parallel test alone.

Comparison of typical aluminum (397 MCM Al) and copper (3/0 Cu) pigtails after fault testing. Both conductors were at approximately the same starting point prior to the test initiation.



Experimentally determined temperatures of aluminum ignition as a function of the used sample size (Adapted from Trunov et al., 2005).

Actionable Conclusions

1. Large increase in high temperature particles for longer fault clearing times.
2. Significant increase in high temperature particles for higher fault currents.
3. Exponential **decrease** in high temperature particles at ground level based on height of conductor above ground. (The longer the particles fall, the more they cool
4. Drastic increase in high temperature particles for faults involving a cut or broken conductor.
5. Interrupt times are not linear with particle production; faster interrupt times significantly impact fire safety

Enhanced Powerline Safety Settings (EPSS)
Advanced protection settings to reduce fire risk

- PG&E began implementing EPSS, in July 2021. This year, PG&E will be enabling settings when conditions indicate an increased potential for wildfires.
- These settings allow our powerlines to automatically turn off power (tripping) within one-tenth of a second, sacrificing some relay coordination.
  - This can occur when there is a hazard, like a tree branch falling into a line.
- Last year, PG&E saw an significant reduction in reportable ignitions on EPSS-enabled circuits in High Fire-Threat Districts (HFTDs), compared to the last three-year average.
- Amid record drought in 2021, these relay settings reduced CPUC-reportable ignitions that could result in wildfires by 80% on EPSS enabled circuits, compared to the last three-year average.
- In 2022, PG&E expanded the EPSS program to selected radial transmission lines and across all 25,500 distribution line miles in high fire-risk areas and nearby locations in the PG&E system.

https://www.pge.com/en_US/residential/outages/enhanced-powerline-safety-settings/enhanced-powerline-safety-settings.page

Major findings

- For Lift tests (representative of fall times in the field)
  - No fires occurred for faults where all particles were less than 210 °C (the autoignition paper for many combustibles, including paper)
  - Except for copper pigtails, no fires were observed for 0.1 s and 0.25 s fault interrupt times for 3/0 Cu (parallel), #4 ACSR (parallel and pigtail), and 397 MCM Al (parallel and pigtail)
- For all tests (Lift and Cage)
  - Particle production increased in an almost exponential factor as a function of fault time
    - My belief is that the increase in particle count results the material being more vigorously disintegrated into smaller and smaller components (resulting in a theoretical increase of particles at a cubic rate)

Possible Future Research Directions

- A great deal of information was developed for this effort. Additional tests at 7000 amps, possibly at 5500 amps, and maybe replicating 4000 amps, would go a long way to give an idea of the repeatability to the data.
- A high end FLIR camera (or other camera technology) that has 180 frames per second, and that can switch across a wide range of temperature calibration ranges, is critical to helping determine exactly what is occurring to particle life. The model used in the testing here is ten year old technology.
  - Possible funding from Department of Energy or CPUC basic wildfire prevention
- Lift tests alone, with two FLIR cameras, with one pointed at the fault and the other capturing particles as they hit the ground, might give cleaner results

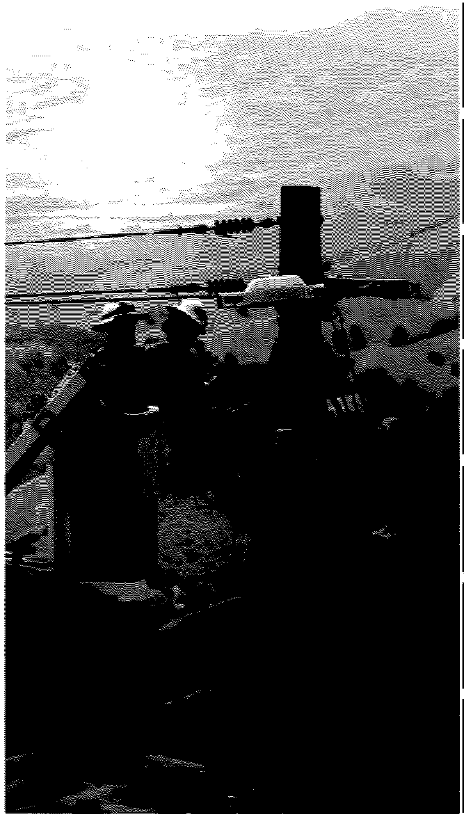
EXHIBIT ICENHOWER-DIRECT-3

Enhanced Powerline Safety Settings

Program Overview

PG&E

Today's Presentation



Topic

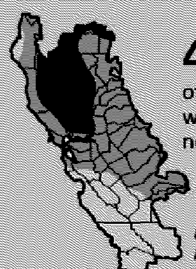
Responding to Evolving Wildfire Risk

2020	2021	2022	2023

Drought-intensified wildfire risk (2020–2022) | **Moderate drought conditions** (2023)

Significant increase in wildfire activity on non-Red Flag Warning (RFW) days (2020–2021)

2020



47%
of acreage burned by wildfires ignited on non-RFW days

U.S. drought monitor Map as of 12/29/2020

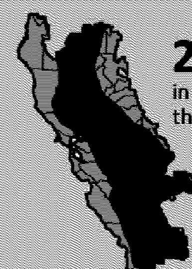
2021

95%
of acreage burned by wildfires ignited on non-RFW days

U.S. drought monitor Map as of 11/2/2021

Implementation of EPSS pilot

2022



2nd driest year
in the last 128 years through peak wildfire season

U.S. drought monitor Map as of 11/1/2022

Expansion of EPSS to all high fire-risk areas

2023

8% of CA remains in drought

U.S. drought monitor Map as of 4/25/2023

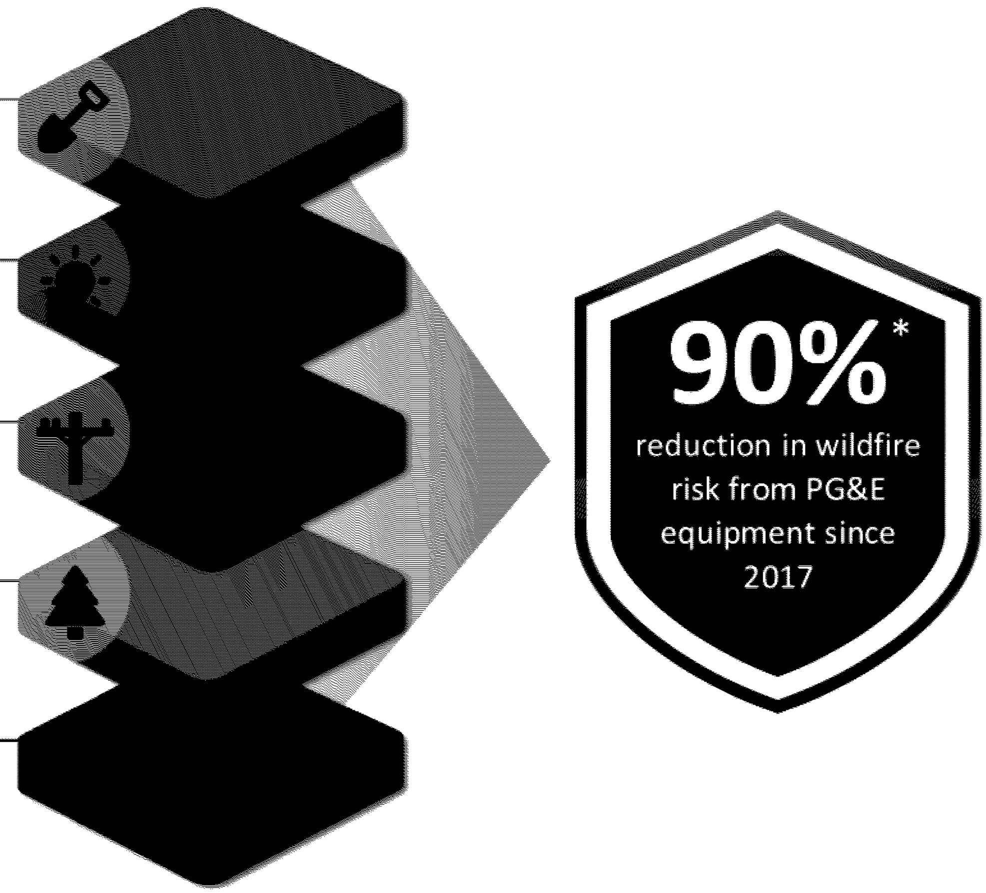
Adding additional protection and refining EPSS

99% reduction in acres burned
68% reduction in ignitions

MAP LEGEND D0: Abnormally dry | D1: Moderate drought | D2: Severe drought | D3: Extreme drought | D4: Exceptional drought

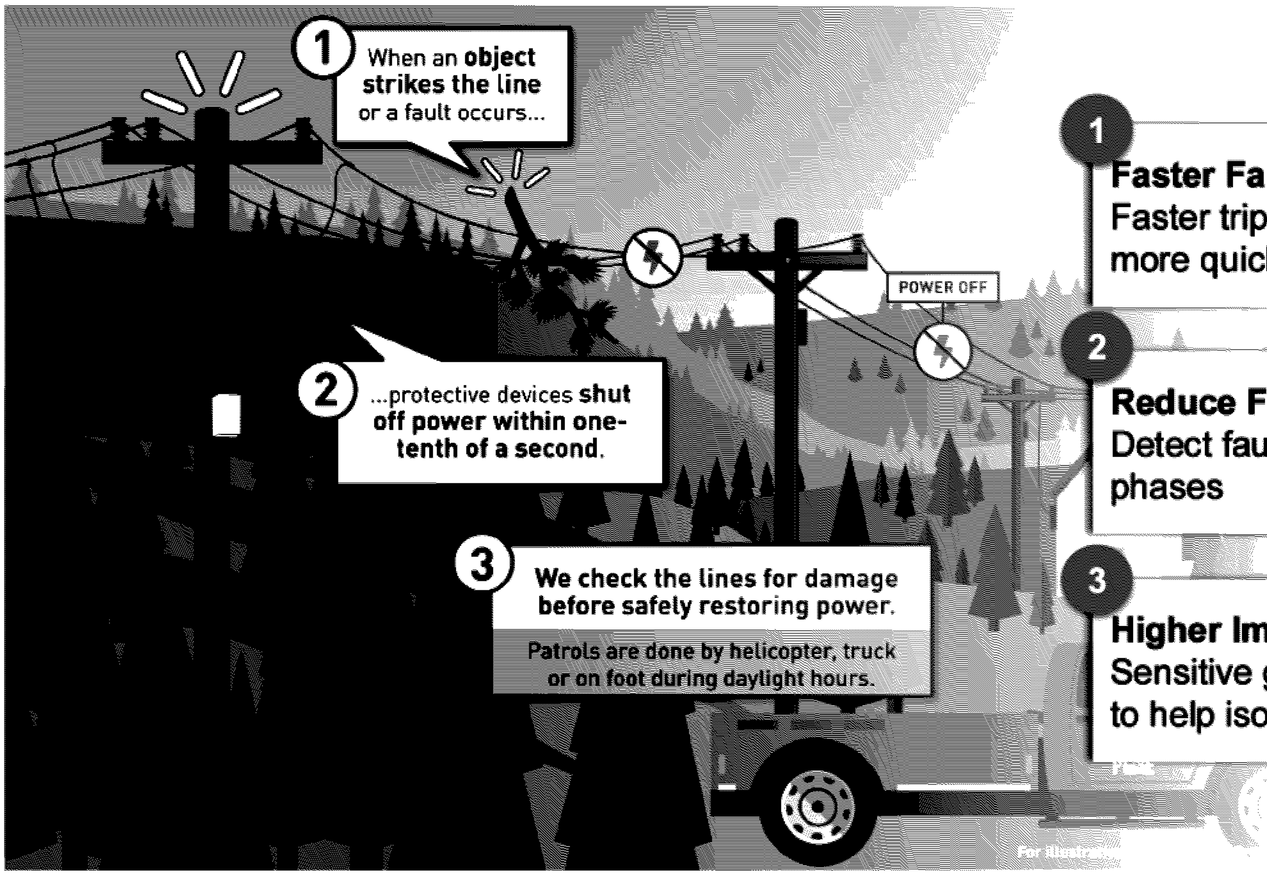
Layers of Protection

- **Undergrounding 10,000 miles of powerlines** in highest fire-risk areas
- **Ensuring safety** with enhanced protection and temporary outages
- **Installing stronger powerlines** and poles
- **Keeping trees and branches away** from powerlines
- **Using the latest technologies** and equipment



1. This number was calculated using the potential safety, reliability and financial impacts of wildfires and their expected frequency, as established by the California Public Utilities Commission.

What Are Enhanced Powerline Safety Settings?



1. **Faster Fault Detection**
   Faster trip settings detect distribution primary faults more quickly to reduce incident fault energy
2. **Reduce Fuse Single Phase Operation**
   Detect faults beyond fuses to clear across all three-phases
3. **Higher Impedance Fault Detection**
   Sensitive ground fault (SGF) elements implemented to help isolate for higher impedance faults

EPSS Mitigates Wildfire Risk

Last year, we expanded the use of EPSS to all powerlines in high fire-risk areas. Expansion drove improvements and these settings helped to prevent wildfires, even with higher risk conditions.

2022 Program Expansion

100% of high fire-risk area line miles protected

1.82M customers protected

374% increase compared to 2021

Despite 31% more days in R3+ conditions we saw a:

68% reduction in ignitions*

99%

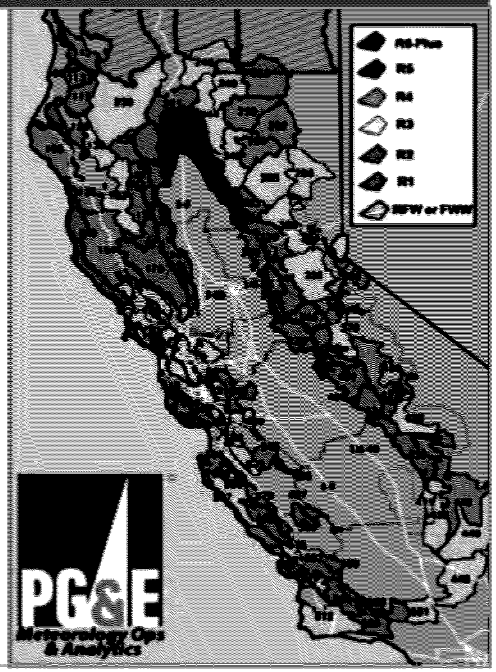
*Data is approximate; *Based on 2022 performance for CPUC-reportable ignitions in HFTD compared to 2018-2020 weather-normalized performance; **Relative to 2018-2020*

FPI Used for EPSS Enablement

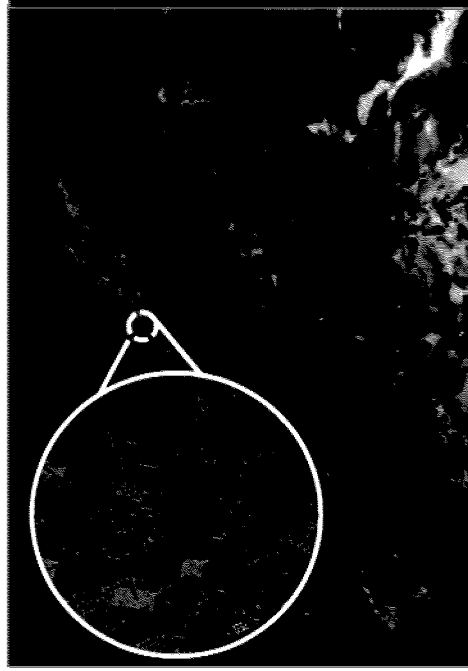
PG&E's MET team calculates FPI values daily at a granular, 2 km pixel level for each hour of the day. When utilizing the FPI forecast these values are adapted to the reporting or risk-based purpose:

Fire Index Areas (FIA) Map

- **FIAs** are geographical areas originally developed by the United States Forest Service (USFS) where fire danger ratings are decided.
- **To aid in understanding of FPI and situational awareness across the service territory, rating outputs represent average FPI values across each FIA for the day**



Fire Potential Index (FPI) for EPSS Enablement

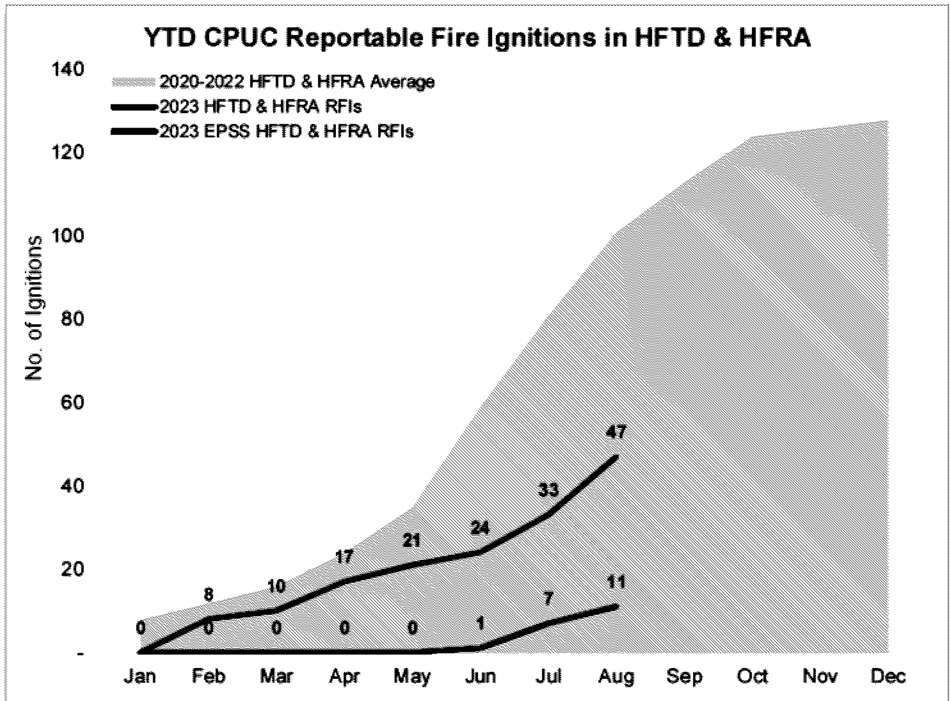


- To identify and mitigate wildfire risk, our EPSS Enablement criteria is reviewed at each 2km pixel for each hour of the day.
- **Circuits are scoped for EPSS if that circuit is forecasted to exceed criteria for at least one hour.**
- **These conditions may exist in a small area or for only a short duration, and not necessarily be reflected on FPI reports that show circuit or daily averages or the circuit may not be in R3 but the FIA is.**

2023 EPSS Program Performance

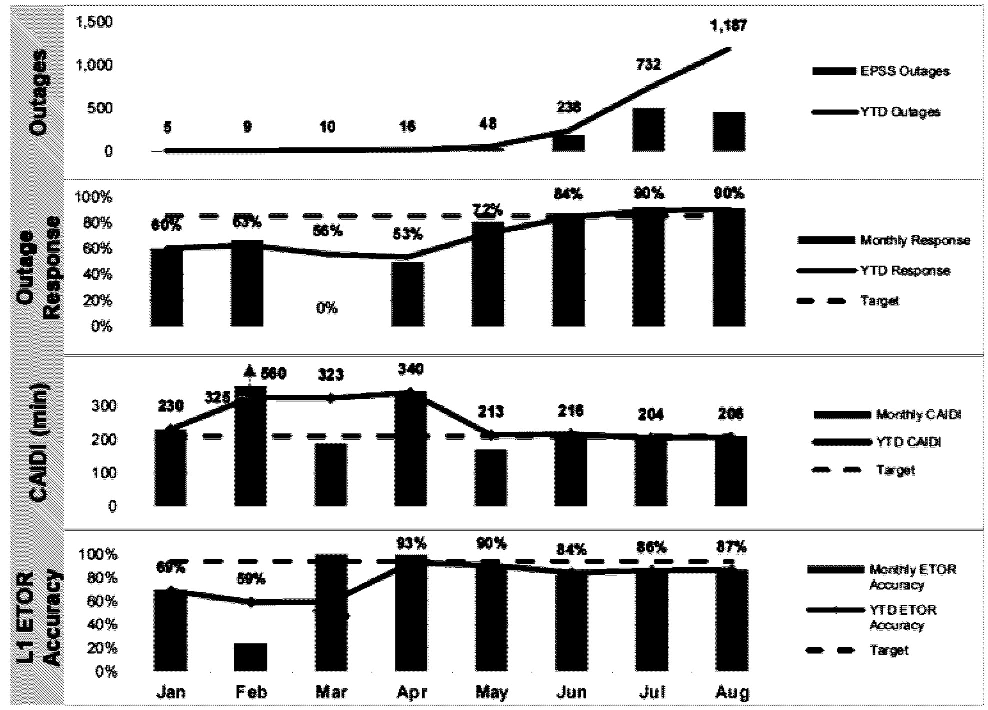
Through June, we have experienced one ignition on an EPSS-enabled zone and continue safely and quickly respond to outages and restore power to our customers.

Ignitions on EPSS Enabled Zones:



1.Data through August 28, 2023 as of August 29, 2023.

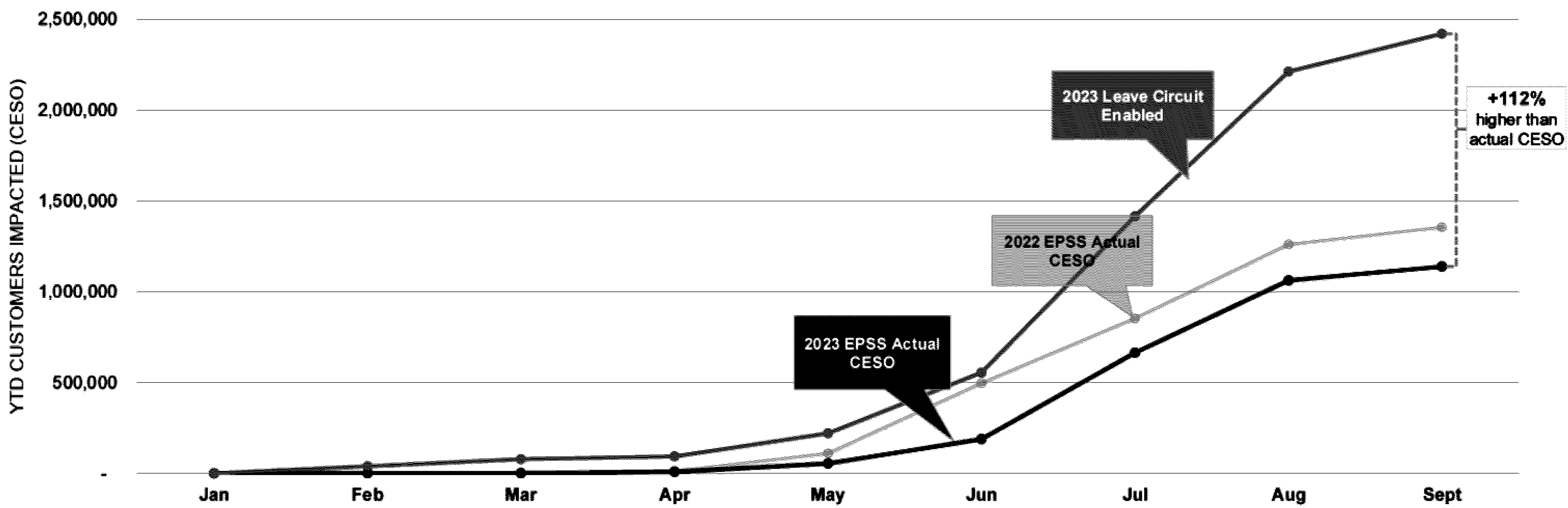
Outages on EPSS Enabled Zones:



Customer Impact of Improved Operational Capabilities

Our operational capability to enable EPSS during periods of elevated wildfire risk and return our circuits to normal when it is safe to do so has helped to reduce the scope of outages in 2022.

2022 vs. 2023 Avoided Customer Impact by Projected CESO



1.Circuits and Miles enabled is the number of unique circuits and associated miles enabled each month.

Minimizing Customer Impacts

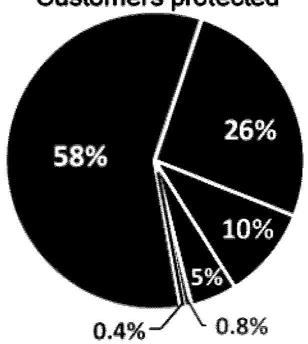
2022

2023

We mitigated customer impacts, without compromising the wildfire prevention benefits of EPSS leveraging real-time improvements:

1.82M

Customers protected



CUSTOMERS EXPERIENCING
0 Outages
1-2 Outages
3-4 Outages
5-7 Outages
8-9 Outages
10+ Outages

In 2023, we are taking actions to support our most impacted customers who experienced 8 or more outages on EPSS enabled zones in 2022:

- **Proactive animal mitigation consisting of bird retrofitting and critter abatement**
- **Proactive and ad-hoc vegetation management**
- **Comprehensive reliability work on targeted circuit protection zones**
- **Expanding existing customer resiliency initiatives like our Residential our Residential Storage Initiatives and our Generator and Battery Rebate Program**

1.Data as of December 31, 2022.

Fault Categorization & EPSS Protection

Technologies and processes such as Partial Voltage Force Out and Down Conductor Detection (DCD) are intended to target the grid effects of faults and their corresponding ignition risk that are not fully mitigated through EPSS.

Very Low initial Current Faults	Low Current ("Hi-Z") Faults	High Current Faults
• Back Feed • Open Circuit • Pole Fires (Hi-Z) • Secondary Faults • Vegetation Contact	• Wire Down • Secondary Fault • Back Feed • Vegetation Contact	• Three Phase • Line to Line ("LL") • Line to Ground ("LG") **Faults where all fuses failed to operate (Ganged Operation)**
Not Protected by EPSS 0-15 Amps Faults <15 Seconds Faults	**Sensitive Ground Fault (SGF)** 15A < Fault Current < Fast-trip currents for >=15 seconds	**Fast Trip (<=100ms)** Preset trip points for LL and LG

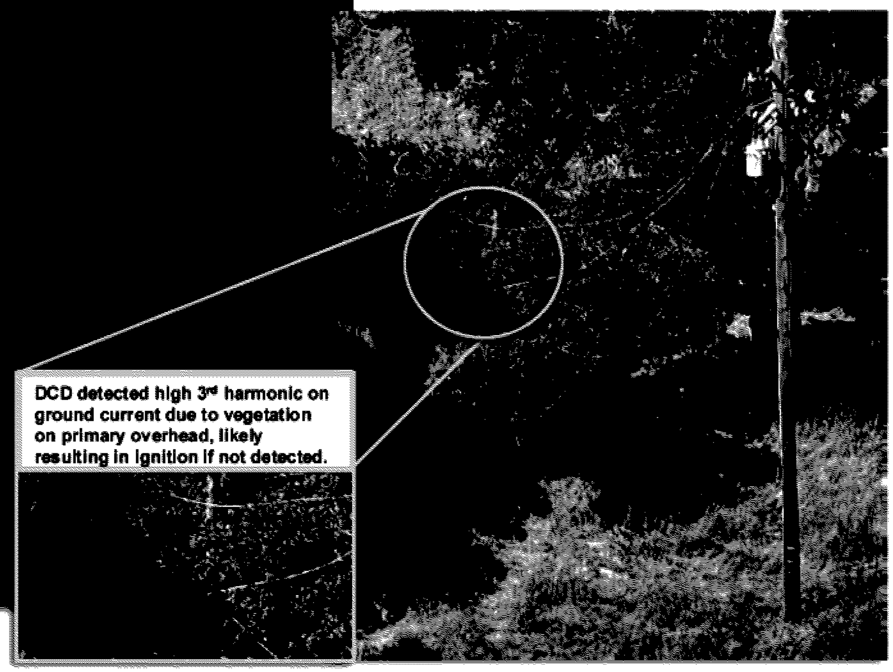
Increasing EPSS Effectiveness

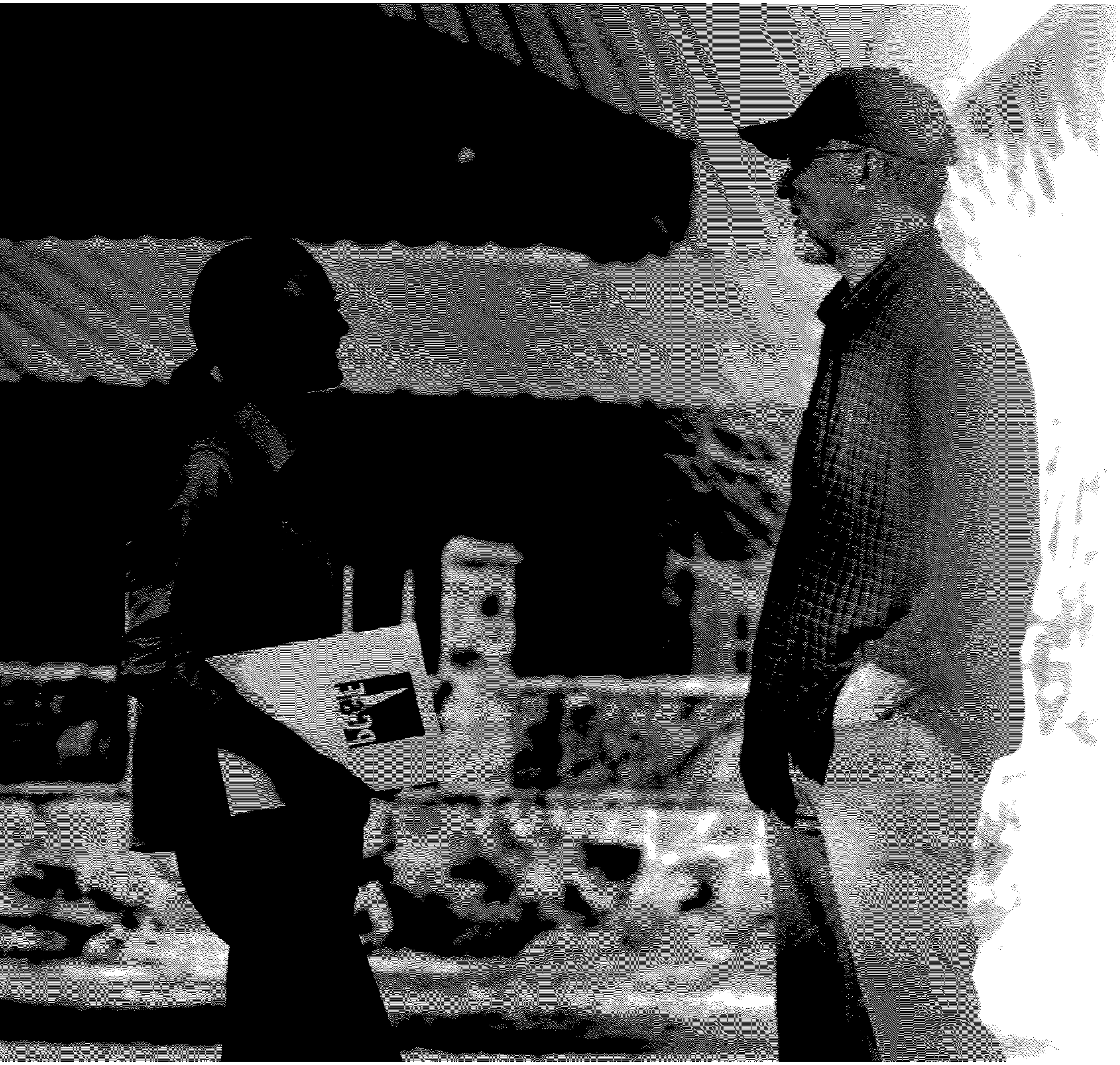
Down Conductor Detection Outage Review Process

Each day, our Protection Engineering team reviews EPSS outages on DCD enabled devices and assesses device performance for potential DCD-related tripping.

- Decision making due to **detailed real-time and post event analysis** of DCD outages.
- Oscillography events are reviewed for **potential triggers** indicating a high impedance ground fault.
- **Refine strategies and response measures** based on learning from DCD outage events.

[redacted]

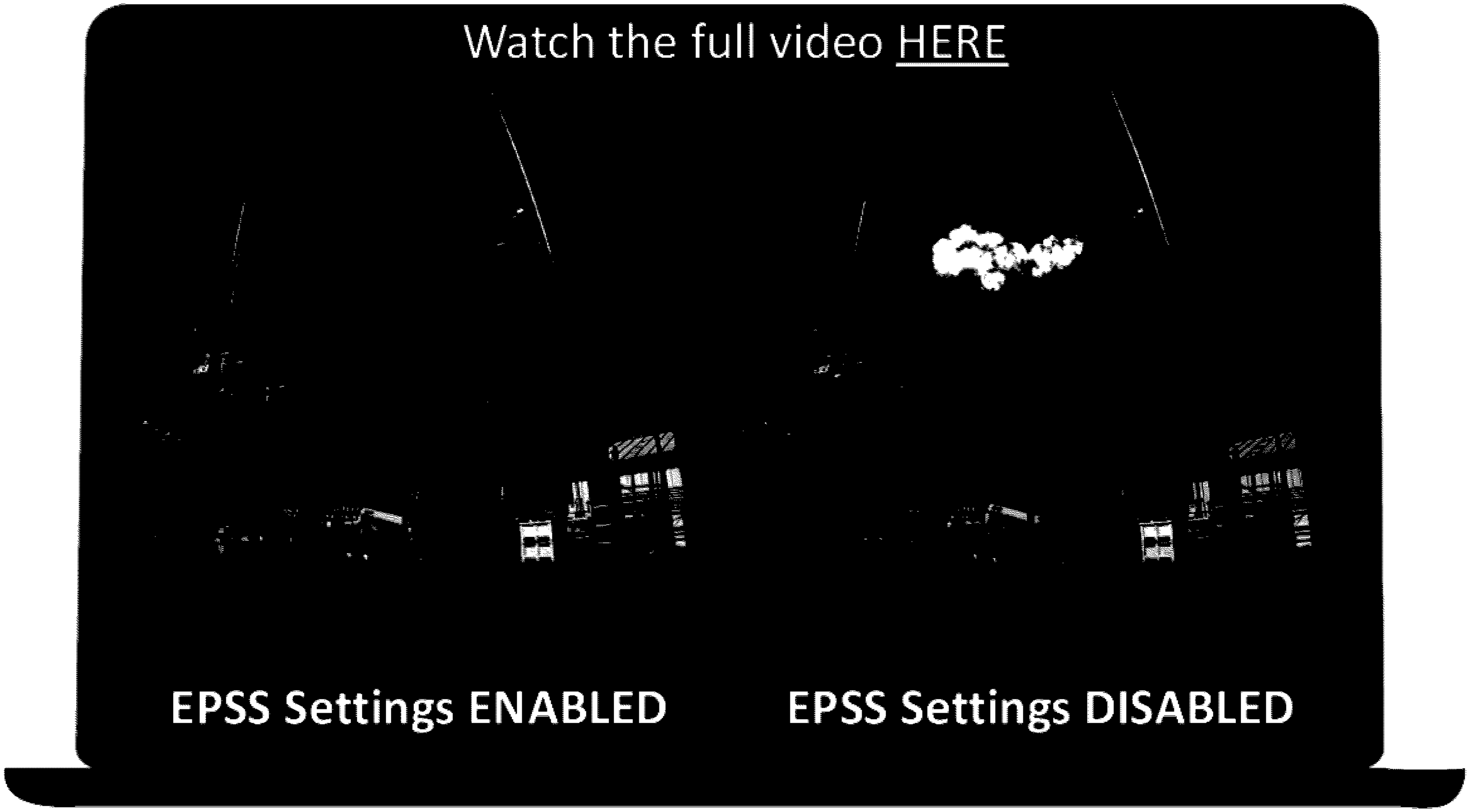




Questions, Comments & Closing

APPENDIX

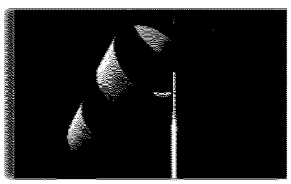
How Does EPSS Work?



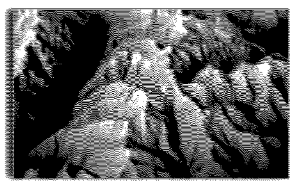
PG&E's Utility Fire Potential Index (FPI)

The EPSS Enablement criteria in HFRA is based on the 2x2km model outputs from our Fire Potential Index (FPI) for every circuit – enabling EPSS where and when necessary to mitigate ignitions.

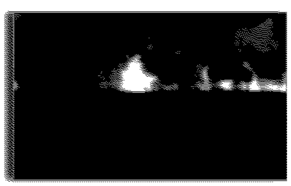
PG&E's current FPI Model is trained to identify localized wildfire risk based on a variety of key risk indicators derived from fire science as well as lessons learned from previous catastrophic wildfires



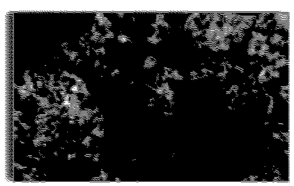
Weather
- Wind Speed
- Turbulence
- Temperature
- Vapor pressure deficit



Topography
- Ruggedness
- Slope
- Wind-terrain alignment



Fuel Moisture
- Dead fuel moisture
- Woody live fuel moisture
- Herbaceous live fuel moisture

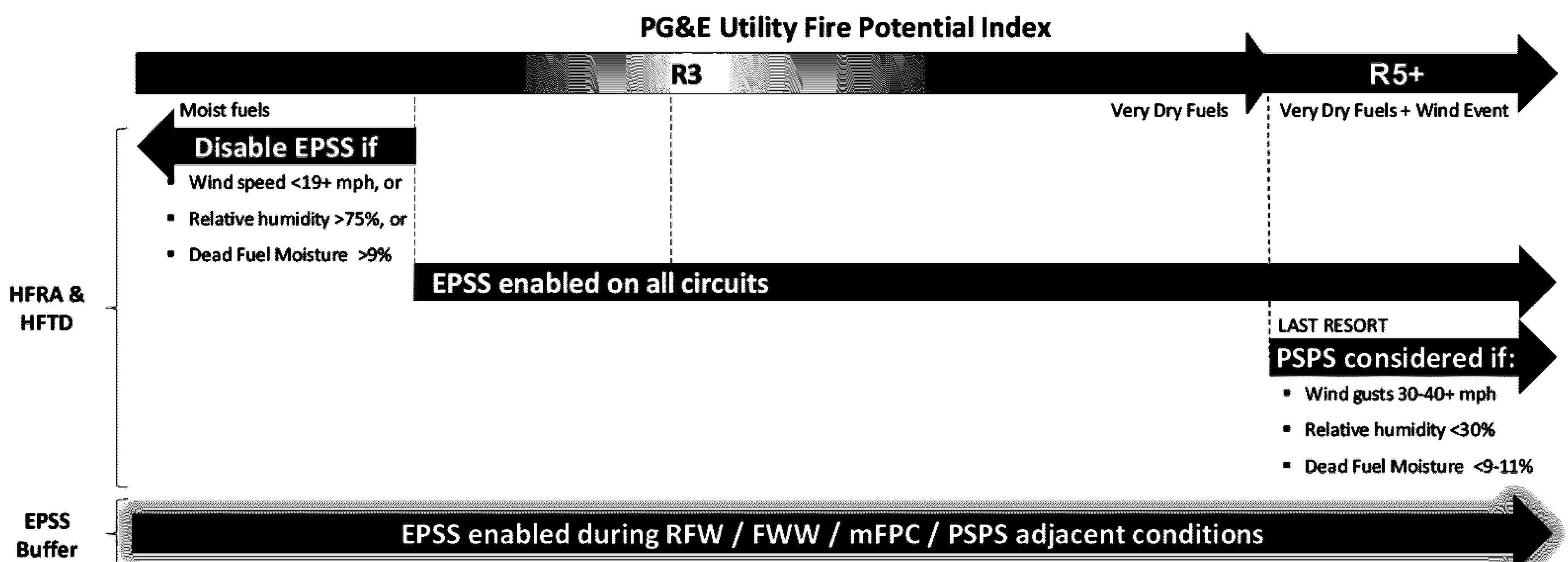


Fuel Model Type
- Grass
- Shrub
- Timber
- Urban

Key Model Components
- Historical satellite fire detection data set from Sonoma Technology Inc. that includes fire growth in California from 2012 - 2020
- Data from PG&E's 31-year weather climatology study
- Technosylva fuel moistures and granular fuel type maps
- Forecasting hourly probability of large and catastrophic fires
- Maximizing predictive skill with state-of-the-art machine learning models
- Greater predictive skill than previous model confirmed by statistical evaluation and comparison of historical fires

EPSS Peak Season Enablement Criteria

EPSS peak season enablement criteria is very conservative, enabling when risk conditions meet or exceed conditions that historically account for 97% of acres burned and 100% of property damage.



NOTE: RFW = Red Flag Warning; **FWW** = Fire Weather Watch; **mFPC** = Minimum Fire Potential Conditions **PSPS** = Public Safety Power Shutoff

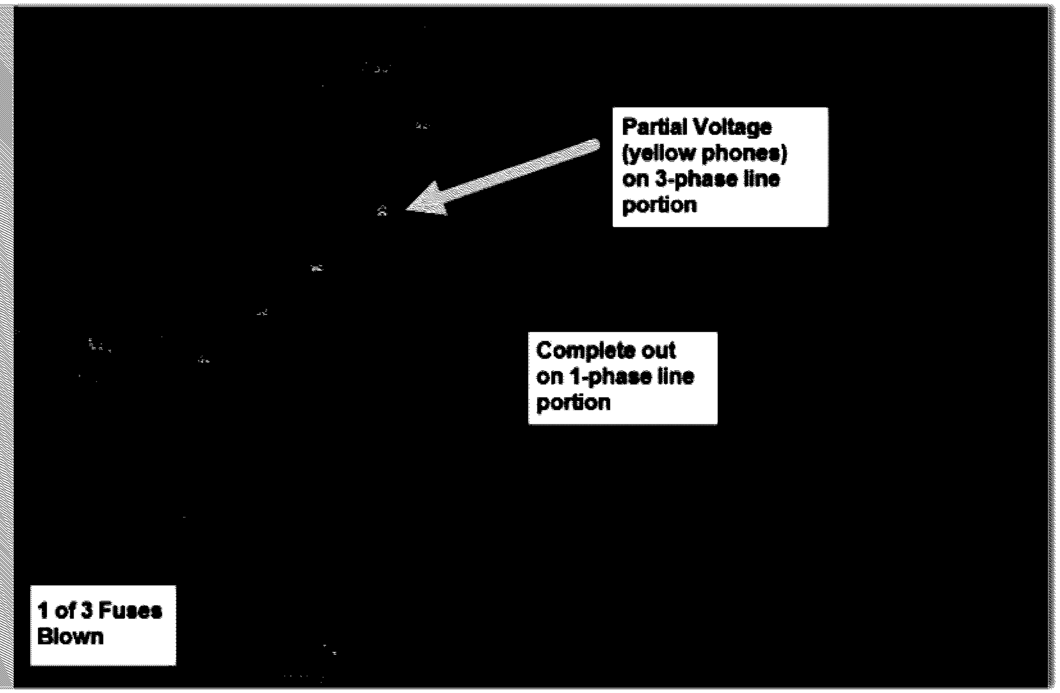
Smart Meter Partial Voltage Detection

To support our identification and response to low and very-low initial current (high-impedance) faults, PG&E is utilizing new data-driven capabilities leveraging our SmartMeter network

SmartMeter Partial Voltage Alert Details:

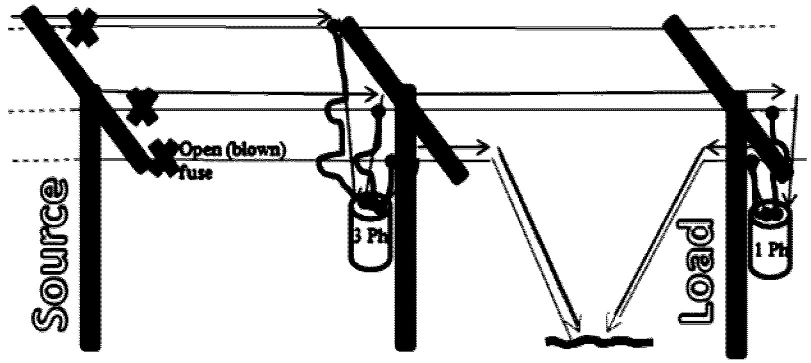
- **PV Alerts work for the 3 wire distribution system with Line-to-Line connected transformers.**
- **PV Alert indicates low SmartMeter Voltage (25 - 75% of nominal 240V)**
- **Network Interface Card (NIC) remains on and able to return pings down to 25% Voltage, while metrology turns off at 75% voltage**
- **New PV alert configuration settings prevent nuisance alerts from transient conditions**
  - Partial Voltage Detection Alert (after 45 seconds of persistence + 20 second trap send wait time)
  - Partial Voltage Repeat Alert (repeats every 20 minute)
  - Partial Voltage Clear Alert (after 90 seconds of normal Voltage persistence)

EXAMPLE VISUALIZATION IN DMS



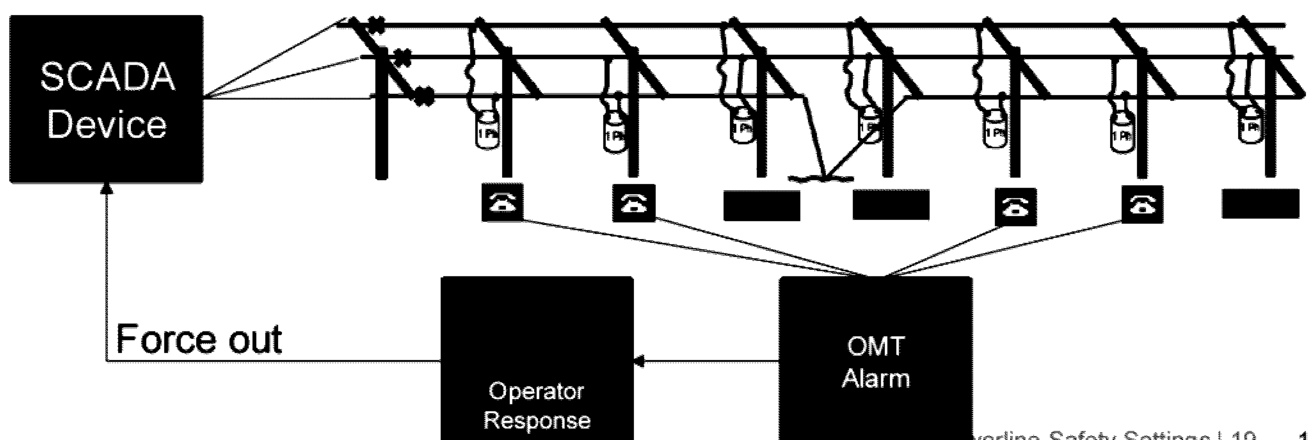
Smart Meter Partial Voltage Detection

Why set protection to look past fuses and other single phase protection?



- Backfeed due to single phase fuse operation can cause high impedance fault.
- Not all cases can be cleared with upstream protection, but high percentage can.
- Some fuse link types (current limiting) can contribute to more uncleared/high impedance faults under this condition

Future usage of AMI coupled with force out could solve gap where EPSS is not effective



AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOSHUA ICENHOWER, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: December 17, 2024

Joshua Icenhower

JOSHUA ICENHOWER

CARY SHELTON-PATCHELL

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
and Sierra Pacific Power Company d/b/a NV Energy

First Amendment to the 2023 Natural Disaster Protection Plan
Docket No. 24-12XXX

Prepared Direct Testimony of

Cary Shelton-Patchell

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Cary Shelton-Patchell. My current position is Regulatory Financial Policy Director for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. I am responsible for the development and implementation of financial regulatory strategies and ensuring compliance with regulatory policies.

3. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I hold a Bachelor of Science degree in Business Administration from the University of Nevada, Reno and I am a Certified Public Accountant. I joined the Companies in 1992 as the Accounting Manager at Lands of Sierra. Since that time, I have held several positions in the Companies, including Lead Revenue Accountant, Staff Accountant III, Regulatory Accounting Manager, Pricing Specialist, Senior Business Analyst, Revenue Requirement and Federal Energy Regulatory Commission ("FERC") Manager and Director, Revenue Requirement and Regulatory Accounting. I assumed the role of Regulatory Financial Policy Director in May 2024. My statement of qualifications is attached as **Exhibit Shelton-Patchell-Direct-1.**

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have previously testified before the Commission in several dockets which are listed in **Exhibit Shelton-Patchell-Direct-1**. Most recently, I filed testimony in the Natural Disaster Protection Plan ("NDPP") Regulatory Asset Recovery Docket No. 24-03006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is support the anticipated rate impact calculations for this NDPP plan amendment for plan years 2024, 2025 and 2026.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring the following Exhibit:

Exhibit Shelton-Patchell-Direct- 1 Statement of Qualifications

Exhibit Shelton-Patchell-Direct-2 NDPP Rate Calculations

Exhibit Shelton-Patchell Direct-3 Residential Bill Impacts

7. Q. PLEASE DESCRIBE THE RATE COMPONENTS FOR THE NDPP.

A. The NDPP rate components include: the NDPP Operations, Maintenance, Administrative and General ("OMAG") Component and the NDPP Capital Component. The OMAG Component for each company consists of the total NDPP OMAG Distribution costs and the NDPP allocated OMAG Transmission costs. The NDPP Capital Component for each company is the total NDPP Capital Distribution costs and the NDPP allocated Capital Transmission Costs.

8. Q. WHAT ARE THE TOTAL NDPP RATES FOR EACH COMPANY WHEN THE IMPACT OF THE REVISED COSTS OF THIS FILING ARE REFLECTED IN THE NDPP COSTS ORIGINALLY FILED IN DOCKET NO. 23-03003 FILING?

A. **Exhibit Shelton-Patchell-Direct-2** calculates the total NDPP rates for each company incorporating the revised costs in this filing with the costs originally filed in Docket No. 23-03003. **Table-Shelton-Patchell – Direct -1** summarizes the rates calculated in **Exhibit Shelton-Patchell-Direct-2**.

Table Shelton-Patchell -Direct -1

NDPP Rates per kWh

	Nevada Power	**Sierra**
2024	$ 0.00047	$ 0.00419
2025	$ 0.00062	$ 0.00473
2026	$ 0.00066	$ 0.00485

9. Q. HOW DO THE RATES CALCULATED FOR THIS FILING COMPARE TO THE RATES FOR THE ORIGINAL PLAN FILING IN DOCKET NO. 23-03003?

A. **Table-Shelton-Patchell-Direct-2** shows the increase or decrease in the rate calculations for each company for the plan period.

Table Shelton-Patchell -Direct -2

	NDPP 1st Amendment	Docket No. 23-03003 NDPP Plan	Increase / <Decrease>
Nevada Power			
2024	$ 0.00047	$ 0.00070	<$ 0.00023>
2025	$ 0.00062	$ 0.00055	$ 0.00007
2026	$ 0.00066	$ 0.00054	$ 0.00012
Sierra			
2024	$ 0.00419	$ 0.00467	<$ 0.00043>
2025	$ 0.00473	$ 0.00444	$ 0.00029
2026	$ 0.00485	$ 0.00446	$ 0.00039

10. Q. WHAT IS THE ESTIMATED CHANGE IN MONTHLY RESIDENTIAL BILLS RESULTING FROM THE RATE INCREASES OR DECREASES REFLECTED IN TABLE SHELTON-PATCHELL DIRECT-2?

A. **Table-Shelton-Patchell-Direct-3** shows the rate change effects for single-family monthly bills and **Table-Shelton-Patchell-Direct-4** shows the rate change effects for multi-family monthly bills.

Table Shelton-Patchell-Direct-3

Single Family Monthly Typical Bill Change

	Nevada Power	Sierra
2024	<$ 0.24>	<$ 0.33>
2025	$ 0.07	$ 0.22
2026	$ 0.13	$ 0.30

Table Shelton-Patchell-Direct-4

Multi-Family Monthly Typical Bill Change

	Nevada Power	**Sierra**
2024	<$ 0.15>	<$ 0.19>
2025	$ 0.05	$ 0.13
2026	$ 0.08	$ 0.17

11. Q. DID YOU CALCULATE A MONTHLY TYPICAL BILL IMPACT FOR RESIDENTIAL CUSTOMERS USING THE CALCULATED TOTAL RATES FROM EXHIBIT SHELTON-PATCHELL DIRECT-2?

A. Yes. **Exhibit Shelton-Patchell Direct-3** calculates the monthly bill impacts when the revised costs of this amendment filing are combined with the costs originally filed in Docket No. 23-03003 for typical single family and multi-family residential customers. These bill impacts are summarized the following **Table-Shelton-Patchell–Direct-5** and **Table-Shelton-Patchell–Direct-6**.

Table Shelton-Patchell-Direct-5

Single Family Monthly Typical Bill Impacts

	Nevada Power	**Sierra**
2024	$ 0.50	$ 3.18
2025	$ 0.65	$ 3.59
2026	$ 0.70	$ 3.68

Table Shelton-Patchell-Direct-6

Multi-Family Monthly Typical Bill Impacts

	Nevada Power	**Sierra**
2024	$ 0.31	$ 1.88
2025	$ 0.41	$ 2.12
2026	$ 0.43	$ 2.17

12. Q. DID YOU MAKE ANY ASSUMPTIONS IN DEVELOPING THE RATE IMPACT CALCULATIONS?

A. Yes. I made the following assumptions:

- The OMAG and capital costs follow what has been presented in this amendment filing and would actually be incurred as planned.
- The recovery of the NDPP costs from customers does not result in any over- or under-recovery of these costs from customers.
- The transmission and distribution OMAG costs are allocated to each company based on where the expenditures occurred in compliance with Section 7, subsection 3 of the regulations adopted as Approved Regulation Legislative Counsel Bureau ("LCB") File No. R181-24 by the Commission on October 11, 2024.
- The OMAG transmission costs for NDPP recovery are allocated for recovery from Nevada customers based on the Nevada jurisdictional transmission allocator established in the most recent general rate case ("GRC") proceeding for each company.
- Transmission and distribution capital and OMAG costs have been allocated between transmission and distribution based on how these costs have been incurred/recorded.
- The projected sales forecast filed in Docket No. 24-05041 was used to calculate the per kWh rates.
- The rates are calculated based on the balancing account recovery because the rate design for NDPP recovery under the GRC has not been determined and the kWh rate that is calculated provides a reasonable basis to evaluate the impact of this filing.

13. Q. DO YOU BELIEVE THESE ASSUMPTIONS ARE REASONABLE?

A. I believe these assumptions are reasonable, are similar to the assumptions that I used in the original plan filing in Docket No. 23-03003 and allow the Commission to determine the impact of this amendment.

14. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT SHELTON-PATCHELL-DIRECT-1

Statement of Qualifications
for
CARY R. SHELTON-PATCHELL

Summary of Qualifications

32 years of regulatory, accounting and utility leadership experience. Experience in regulatory and operations accounting areas. Extensive knowledge of regulatory activities and regulatory accounting for NV Energy's Nevada and California jurisdictions.

Professional Experience

Regulatory Financial Policy Director
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
May 2024 - present

Responsible for development and implementation of financial regulatory strategies and ensuring compliance with regulatory policies.

Director, Revenue Requirement and Regulatory Accounting
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
January 2022 – May 2024

Responsible for regulatory filings, tariff development, Nevada deferred energy filings, revenue requirement calculations and jurisdictional allocations related to general rate case filings.

Revenue Requirement and FERC Manager
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
May 2021 – January 2022

Responsible for the preparation of regulatory earned rate of return, earnings sharing calculations and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings. Managed fuel and purchased power recovery mechanisms and required filings along with the completion of various state and FERC reporting requirements.

Senior Business Analyst
Sierra Pacific Power Company d/b/a NV Energy
December 2016 – May 2021

Responsible for compliance with company policies, procedures and regulations including SOX. Supported Sierra Pacific Power Gas Department in the development and reporting of budgets, forecasts and investments.

Pricing Specialist
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
March 2008 – December 2016

Responsible for the preparation of the Sierra Gas Department Embedded Cost of Service Study and Rate Design, the development and support of impact calculations for customers electing distribution only service, development of revenue budget inputs.

Manager, Regulatory Accounting
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
September 1999 - March 2008

Responsible for the timely preparation of regulatory statements, adjustments and analyses, the implementation of accounting procedures to comply with regulatory orders and developments. Managed the preparation of calculations and studies pertaining to recorded revenues and lead/lag studies.

Staff Accountant III, Restructuring Team
Sierra Pacific Power Company d/b/a NV Energy
May 1998 - September 1999

Responsible for the drafting of Sierra Pacific's comments filed with the Nevada Public Utilities Commission for past costs and proposed alternative seller licensing. Assisted in defining the accounting resources that were required to complete filings required by the restructuring initiatives implemented by the Nevada legislature and Public Utilities Commission of Nevada (PUCN). Assumed position of Remittance Processing Interim Supervisor and was responsible for costs, timing and implementation of a project to integrate processing of Nevada Power's mail-in payments into the Reno Remittance Department's workflow.

Lead Revenue Accountant, Corporate Accounting
Sierra Pacific Power Company d/b/a NV Energy
June 1994 - May 1998

Responsible for company-wide margin/revenue reporting and prepared monthly revenue variance analysis for management. Implemented and developed accounting procedures for new revenue programs and specialized contracts. Participated as the accounting department representative in the Customer Management Reengineering Team, California Direct Access Implementation Team, and Customer Information System Replacement Team.

Accounting Manager
Lands of Sierra
April 1992 - June 1994

Responsible for monthly financial reporting and compliance with generally accepted accounting principles to Sierra Pacific Resources. Supervised staff in areas of general ledger, accounts payable, accounts receivable, job cost and cash management.

Senior Staff Accountant
Deloitte & Touche, Reno
September 1989 - April 1992

Responsible for planning and implementing financial and compliance audits in accordance with generally accepted auditing standards. Reviewed and evaluated internal control systems, analyzed financial statements, and related footnote disclosures for compliance with generally accepted accounting principles.

Prior Testimony Before the Nevada Public Utilities Commission

01-10001	03-10001	06-11022	13-06003	22-03003	22-06014	24-03006
01-11029	03-12002	07-12001	16-06007	22-03004	23-03004	
01-11030	05-10003	10-06002	22-03001	22-03006	24-02026	
02-2002	05-10005	11-06006	22-03002	22-03028	24-02027	

Education

Certified Public Accountant, State of Nevada

University of Nevada, Reno
Bachelor of Science in Business Administration May 1989

Continuing Education Courses
- Utility Finance and Accounting for Financial Professionals
- Complying with Sarbanes-Oxley Section 404
- Electric Rates Advanced Course, Edison Electric Institute
- FASB/APB Update and Review
- Electric Utility Ratemaking Concepts
- Stranded Costs and Securitization: The Transition to a Restructured Industry, Edison Electric Institute
- Stranded Cost Recovery
- The Vital Role of Financial Performance, Western Electric Power Institute
- Competitive Billing Strategies
- Transforming Accounting & Finance, Western Electric Power Institute
- Pricing Strategies & Evolving Regulation
- Fundamentals of Utility Finance
- Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute

Professional Affiliations
- American Institute of Certified Public Accountants
- Nevada Society of Certified Public Accountants

EXHIBIT SHELTON-PATCHELL-DIRECT-2

NV ENERGY
2024-2026 NATURAL DISASTER PROTECTION PLAN ("NDPP") 1st Amendment
NDPP RATES PER kWh

Ln	(a) Year	(b) Reference	(c) NPC	(d) SPPC	Ln
1					1
2	2024	Pg 2, Ln 18	$ 0.00047	$ 0.00419	2
3	2025	Pg 3, Ln 18	$ 0.00062	$ 0.00473	3
4	2026	Pg 4, Ln 18	$ 0.00066	$ 0.00485	4

NV ENERGY
2024-2026 NDPP 1st AMENDMENT
CALCULATION OF NDPP RATE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2024
(IN THOUSANDS)

Ln	(a) Description	(b) Reference	(c) NPC	(d) SPPC	Ln
1					1
2	**NDPP OMAG Component**				2
3	Total NDPP OMAG Distribution Costs	Pg 5 & 6, Col (o), Ln 27	$ 8,700	$ 50,870	3
4	NDPP Allocated OMAG Transmission Costs	Pg 5 & 6, Col (o), Ln 28	92	1,983	4
5					5
6	Total NDPP OMAG Costs		$ 8,792	$ 52,853	6
7					7
8	**NDPP Capital Component**				8
9	Total NDPP Capital Distribution Costs	Pg 5 & 6, Col (o), Ln 13	$ 2,481	$ 4,753	9
10	NDPP Allocated Capital Transmission Costs	Pg 5 & 6, Col (o), Ln 14	111	69	10
11					11
12	Total NDPP Capital Costs		$ 2,592	$ 4,822	12
13					13
14	**Total NDPP Costs for Recovery** (Ln 6 + Ln 12)		**$ 11,384**	**$ 57,675**	14
15					15
16	kWh Sales [1]	Pg 7, Col (b) & (c), Ln 3	24,341,070,735	13,751,001,068	16
17					17
18	**NDPP per kWh** (Ln 14 ÷ Ln 16)		**$ 0.00047**	**$ 0.00419**	18
19			To Pg 1, Col (c) & (d), Ln 2		19
20	[1] Total kWh includes all customers - Retail and DOS, based on forecasted sales				20
21					21
22					22

NV ENERGY
2024-2026 NDPP 1st AMENDMENT
CALCULATION OF NDPP RATE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2025
(IN THOUSANDS)

Ln	(a) **Description**	(b) **Reference**	(c) **NPC**	(d) **SPPC**	Ln
1					1
2	**NDPP OMAG Component**				2
3	Total NDPP OMAG Distribution Costs	Pg 5 & 6, Col (o), Ln 56	$ 10,654	$ 54,670	3
4	NDPP Allocated OMAG Transmission Costs	Pg 5 & 6, Col (o), Ln 57	1,194	7,318	4
5					5
6	Total NDPP OMAG Costs		$ 11,847	$ 61,988	6
7					7
8	**NDPP Capital Component**				8
9	Total NDPP Capital Distribution Costs	Pg 5 & 6, Col (o), Ln 42	$ 3,456	$ 8,485	9
10	NDPP Allocated Capital Transmission Costs	Pg 5 & 6, Col (o), Ln 43	154	119	10
11					11
12	Total NDPP Capital Costs		$ 3,611	$ 8,604	12
13					13
14	**Total NDPP Costs for Recovery** (Ln 6 + Ln 12)		**$ 15,458**	**$ 70,592**	14
15					15
16	kWh Sales [1]	Pg 7, Col (b) & (c), Ln 4	24,755,031,157	14,929,807,556	16
17					17
18	**NDPP per kWh** (Ln 14 ÷ Ln 16)		**$ 0.00062**	**$ 0.00473**	18
19			To Pg 1, Col (c) & (d), Ln 3		19
20	[1] Total kWh includes all customers - Retail and DOS, based on forecasted sales				20
21					21
22					22

NV ENERGY
2024-2026 NDPP 1st AMENDMENT
CALCULATION OF NDPP RATE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026
(IN THOUSANDS)

Ln	(a) **Description**	(b) **Reference**	(c) **NPC**	(d) **SPPC**	Ln
1					1
2	**NDPP OMAG Component**				2
3	Total NDPP OMAG Distribution Costs	Pg 5 & 6, Col (o), Ln 85	$ 10,073	$ 58,200	3
4	NDPP Allocated OMAG Transmission Costs	Pg 5 & 6, Col (o), Ln 86	1,121	6,965	4
5					5
6	Total NDPP OMAG Costs		$ 11,194	$ 65,165	6
7					7
8	**NDPP Capital Component**				8
9	Total NDPP Capital Distribution Costs	Pg 5 & 6, Col (o), Ln 71	$ 5,134	$ 12,604	9
10	NDPP Allocated Capital Transmission Costs	Pg 5 & 6, Col (o), Ln 72	229	177	10
11					11
12	Total NDPP Capital Costs		$ 5,363	$ 12,781	12
13					13
14	**Total NDPP Costs for Recovery** (Ln 6 + Ln 12)		**$ 16,557**	**$ 77,946**	14
15					15
16	kWh Sales [1]	Pg 7, Col (b) & (c), Ln 5	25,257,238,027	16,078,433,449	16
17					17
18	**NDPP per kWh** (Ln 14 ÷ Ln 16)		**$ 0.00066**	**$ 0.00485**	18
19			To Pg 1, Col (c) & (d), Ln 4		19
20	[1] Total kWh includes all customers - Retail and DOS, based on forecasted sales				20
21					21
22					22

NEVADA POWER COMPANY
d/b/a NV ENERGY
2024-2026 NDPP 1st AMENDMENT
(IN DOLLARS)

Ln	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	Ln	Reference
1	Carry Charge	7.43% effective 01/01/2024			2.42% excluding equity component effective 10/01/2024										1	
2														Summary of	2	
3		January	February	March	April	May	June	July	August	September	October	November	December	Annual Activity	3	Reference
4															4	
5	**PERIOD 6 (2024 Cost Recovery)**														5	
6	**Account No. 182-3XX**														6	
7	**Capital Costs**														7	
8	Depreciation Expense	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 54,634	$ 655,611	8	
9	Return on Rate Base	136,777	141,607	146,437	151,267	156,097	160,927	165,757	170,588	175,418	180,248	185,078	189,908	1,960,109	9	
10	Subtotal	191,411	196,241	201,071	205,901	210,732	215,562	220,392	225,222	230,052	234,882	239,712	244,542	2,615,720	10	
11															11	
12	Beginning Balance	$ -	$ 189,644	$ 384,074	$ 583,289	$ 787,290	$ 996,076	$ 1,209,648	$ 1,428,005	$ 1,651,148	$ 1,879,076	$ 2,111,790	$ 2,349,289	$ -	12	
13	Distribution - 94.84%	181,537	186,118	190,699	195,280	199,861	204,442	209,023	213,604	218,185	222,766	227,347	231,928	2,480,790	13	To: Pg 2, Col (c), Ln 9
14	Transmission - 5.16% (Demand Allocator 82.10%)	8,107	8,311	8,516	8,721	8,925	9,130	9,334	9,539	9,743	9,948	10,153	10,357	110,784	14	To: Pg 2, Col (c), Ln 10
15															15	
16	2024 Total Capital Balance for Recovery	$ 189,644	$ 384,074	$ 583,289	$ 787,290	$ 996,076	$ 1,209,648	$ 1,428,005	$ 1,651,148	$ 1,879,076	$ 2,111,790	$ 2,349,289	$ 2,591,574	$ 2,591,574	16	
17															17	
18	**OMAG Costs**														18	
19	Beginning Balance	$ -	$ 716,212	$ 1,436,858	$ 2,161,966	$ 2,891,563	$ 3,625,677	$ 4,364,336	$ 5,107,569	$ 5,855,403	$ 6,607,866	$ 7,334,429	$ 8,062,457	$ -	19	
20	Distribution - 98.94%	704,388	704,388	704,388	704,388	704,388	704,388	704,388	704,388	704,388	704,388	704,388	704,388	8,452,661	20	
21	Transmission - 1.06%	7,417	7,417	7,417	7,417	7,417	7,417	7,417	7,417	7,417	7,417	7,417	7,417	88,999	21	
22	Subtotal	711,805	1,428,017	2,148,663	2,873,771	3,603,368	4,337,482	5,076,141	5,819,374	6,567,208	7,319,671	8,046,234	8,774,262	8,541,660	22	
23															23	
24	Carrying Charge Period 6 - Dist	4,361	8,749	13,164	17,607	22,077	26,574	31,100	35,654	40,235	14,604	16,054	17,506	247,685	24	
25	Carrying Charge Period 6 - Trans	46	92	139	185	232	280	327	375	424	154	169	184	2,608	25	
26															26	
27	Total OMAG - Distribution	708,749	713,137	717,553	721,995	726,465	730,963	735,488	740,042	744,624	718,993	720,442	721,895	8,700,346	27	To: Pg 2, Col (c), Ln 3
28	Total OMAG - Transmisssion	7,462	7,509	7,555	7,602	7,649	7,696	7,744	7,792	7,840	7,570	7,586	7,601	91,607	28	To: Pg 2, Col (c), Ln 4
29															29	
30	2024 Total OMAG Balance for Recovery	$ 716,212	$ 1,436,858	$ 2,161,966	$ 2,891,563	$ 3,625,677	$ 4,364,336	$ 5,107,569	$ 5,855,403	$ 6,607,866	$ 7,334,429	$ 8,062,457	$ 8,791,953	$ 8,791,953	30	
31															31	
32	**2024 Ending Balance for Recovery**	$ 905,856	$ 1,820,932	$ 2,745,255	$ 3,678,853	$ 4,621,753	$ 5,573,984	$ 6,535,574	$ 7,506,550	$ 8,486,942	$ 9,446,219	$ 10,411,746	$ 11,383,526	$ 11,383,526	32	
33															33	
34	**PERIOD 7 (2025 Cost Recovery)**														34	
35	**Account No. 182-3XX**														35	
36	**Capital Costs**														36	
37	Depreciation Expense	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 76,025	$ 912,299	37	
38	Return on Rate Base	194,738	200,725	206,713	212,700	218,687	224,675	230,662	236,650	242,637	248,624	254,612	260,599	2,732,022	38	
39	Subtotal	270,763	276,750	282,738	288,725	294,712	300,700	306,687	312,675	318,662	324,649	330,637	336,624	3,644,322	39	
40															40	
41	Beginning Balance	$ -	$ 268,263	$ 542,459	$ 822,587	$ 1,108,646	$ 1,400,638	$ 1,698,562	$ 2,002,418	$ 2,312,206	$ 2,627,927	$ 2,949,579	$ 3,277,163	$ -	41	
42	Distribution - 94.84%	256,796	262,474	268,153	273,831	279,510	285,188	290,867	296,545	302,224	307,902	313,581	319,259	3,456,332	42	To: Pg 3, Col (c), Ln 9
43	Transmission - 5.16% (Demand Allocator 82.10%)	11,468	11,721	11,975	12,228	12,482	12,736	12,989	13,243	13,496	13,750	14,003	14,257	154,348	43	To: Pg3, Col (c), Ln 10
44															44	
45	2025 Total Capital Balance for Recovery	$ 268,263	$ 542,459	$ 822,587	$ 1,108,646	$ 1,400,638	$ 1,698,562	$ 2,002,418	$ 2,312,206	$ 2,627,927	$ 2,949,579	$ 3,277,163	$ 3,610,680	$ 3,610,680	45	
46															46	
47	**OMAG Costs**														47	
48	Beginning Balance	$ -	$ 976,383	$ 1,954,734	$ 2,935,058	$ 3,917,359	$ 4,901,640	$ 5,887,905	$ 6,876,159	$ 7,866,406	$ 8,858,649	$ 9,852,893	$ 10,849,141	$ -	48	
49	Distribution - 89.91%	876,223	876,223	876,223	876,223	876,223	876,223	876,223	876,223	876,223	876,223	876,223	876,223	10,514,680	49	
50	Transmission - 10.09%	98,195	98,195	98,195	98,195	98,195	98,195	98,195	98,195	98,195	98,195	98,195	98,195	1,178,338	50	
51	Subtotal	974,418	1,950,801	2,929,152	3,909,476	4,891,777	5,876,058	6,862,323	7,850,577	8,840,824	9,833,067	10,827,311	11,823,559	11,693,018	51	
52															52	
53	Carrying Charge Period 7 - Dist	1,767	3,537	5,311	7,088	8,869	10,653	12,442	14,233	16,029	17,828	19,630	21,436	138,822	53	
54	Carrying Charge Period 7 - Trans	198	396	595	794	994	1,194	1,394	1,595	1,796	1,998	2,200	2,402	15,557	54	
55															55	
56	Total OMAG - Distribution	877,990	879,760	881,534	883,311	885,092	886,877	888,665	890,457	892,252	894,051	895,854	897,660	10,653,502	56	To: Pg 3, Col (c), Ln 3
57	Total OMAG - Transmisssion	98,393	98,591	98,790	98,989	99,189	99,389	99,589	99,790	99,991	100,193	100,395	100,597	1,193,896	57	To: Pg 3, Col (c), Ln 4
58															58	
59	2025 Total OMAG Balance for Recovery	$ 976,383	$ 1,954,734	$ 2,935,058	$ 3,917,359	$ 4,901,640	$ 5,887,905	$ 6,876,159	$ 7,866,406	$ 8,858,649	$ 9,852,893	$ 10,849,141	$ 11,847,398	$ 11,847,398	59	
60															60	
61	**2025 Ending Balance for Recovery**	$ 1,244,646	$ 2,497,193	$ 3,757,645	$ 5,026,005	$ 6,302,278	$ 7,586,467	$ 8,878,577	$ 10,178,612	$ 11,486,576	$ 12,802,472	$ 14,126,304	$ 15,458,078	$ 15,458,078	61	
62															62	

NEVADA POWER COMPANY
d/b/a NV ENERGY
2024-2026 NDPP 1st AMENDMENT
(IN DOLLARS)

Ln	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	Ln	
1	Carry Charge	7.43% effective 01/01/2024			2.42% excluding equity component effective 10/01/2024										1	
2														Summary of	2	
3		January	February	March	April	May	June	July	August	September	October	November	December	Annual Activity	3	Reference
4															4	
63	**PERIOD 8 (2026 Cost Recovery)**														63	
64	**Account No. 182-3XX**														64	
65	**Capital Costs**														65	
66	Depreciation Expense	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 118,030	$ 1,416,356	66	
67	Return on Rate Base	266,586	278,674	290,761	302,848	314,936	327,023	339,110	351,197	363,285	375,372	387,459	399,547	3,996,798	67	
68	Subtotal	384,616	396,703	408,791	420,878	432,965	445,053	457,140	469,227	481,314	493,402	505,489	517,576	5,413,154	68	
69															69	
70	Beginning Balance	$ -	$ 381,066	$ 774,107	$ 1,179,124	$ 1,596,117	$ 2,025,085	$ 2,466,029	$ 2,918,949	$ 3,383,845	$ 3,860,716	$ 4,349,563	$ 4,850,386	$ -	70	
71	Distribution - 94.84%	364,776	376,240	387,704	399,167	410,631	422,095	433,559	445,022	456,486	467,950	479,414	490,877	5,133,920	71	To: Pg 4, Col (c), Ln 9
72	Transmission - 5.16% (Demand Allocator 82.10%)	16,290	16,802	17,314	17,825	18,337	18,849	19,361	19,873	20,385	20,897	21,409	21,921	229,264	72	To: Pg 4, Col (c), Ln 10
73															73	
74	2026 Total Capital Balance for Recovery	$ 381,066	$ 774,107	$ 1,179,124	$ 1,596,117	$ 2,025,085	$ 2,466,029	$ 2,918,949	$ 3,383,845	$ 3,860,716	$ 4,349,563	$ 4,850,386	$ 5,363,184	$ 5,363,184	74	
75															75	
76	**OMAG Costs**														76	
77	Beginning Balance	$ -	$ 922,534	$ 1,846,928	$ 2,773,186	$ 3,701,312	$ 4,631,309	$ 5,563,181	$ 6,496,931	$ 7,432,565	$ 8,370,084	$ 9,309,494	$ 10,250,798	$ -	77	
78	Distribution - 89.97%	828,493	828,493	828,493	828,493	828,493	828,493	828,493	828,493	828,493	828,493	828,493	828,493	9,941,915	78	
79	Transmission - 10.03%	92,185	92,185	92,185	92,185	92,185	92,185	92,185	92,185	92,185	92,185	92,185	92,185	1,106,220	79	
80	Subtotal	920,678	1,843,212	2,767,606	3,693,864	4,621,990	5,551,987	6,483,858	7,417,609	8,353,242	9,290,762	10,230,172	11,171,476	11,048,135	80	
81															81	
82	Carrying Charge Period 8 - Dist	1,670	3,344	5,021	6,702	8,386	10,073	11,764	13,458	15,156	16,856	18,561	20,269	131,260	82	
83	Carrying Charge Period 8 - Trans	186	372	559	746	933	1,121	1,309	1,497	1,686	1,876	2,065	2,255	14,605	83	
84															84	
85	Total OMAG - Distribution	830,163	831,837	833,514	835,195	836,879	838,566	840,257	841,951	843,648	845,349	847,054	848,762	10,073,175	85	To: Pg 4, Col (c), Ln 3
86	Total OMAG - Transmisssion	92,371	92,557	92,744	92,931	93,118	93,306	93,494	93,682	93,871	94,061	94,250	94,440	1,120,826	86	To: Pg 4, Col (c), Ln 4
87															87	
88	2026 Total OMAG Balance for Recovery	$ 922,534	$ 1,846,928	$ 2,773,186	$ 3,701,312	$ 4,631,309	$ 5,563,181	$ 6,496,931	$ 7,432,565	$ 8,370,084	$ 9,309,494	$ 10,250,798	$ 11,194,000	$ 11,194,000	88	
89															89	
90	**2026 Ending Balance for Recovery**	$ 1,303,600	$ 2,621,035	$ 3,952,310	$ 5,297,429	$ 6,656,394	$ 8,029,210	$ 9,415,881	$ 10,816,409	$ 12,230,800	$ 13,659,057	$ 15,101,184	$ 16,557,184	$ 16,557,184	90	
91															91	

SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY
2024-2026 NDPP 1st AMENDMENT
(IN DOLLARS)

Ln	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	Ln	
1	Carry Charge	6.95% effective 01/01/2023 to 09/30/2024				2.33% excluding equity component effective 10/01/2024									1	
2														Summary of	2	
3		January	February	March	April	May	June	July	August	September	October	November	December	Annual Activity	3	Reference
4															4	
5	**PERIOD 6 (2024 Cost Recovery)**														5	
6	**Account No. 182-3XX**														6	
7	**Capital Costs**														7	
8	Depreciation Expense	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 123,399	$ 1,480,792	8	
9	Return on Rate Base	206,098	218,940	231,781	244,623	257,464	270,306	283,147	295,988	308,830	339,437	352,988	366,539	3,376,140	9	
10	Subtotal	329,498	342,339	355,180	368,022	380,863	393,705	406,546	419,388	432,229	462,837	476,387	489,938	4,856,933	10	
11															11	
12	Beginning Balance	$ -	$ 327,193	$ 667,137	$ 1,019,833	$ 1,385,280	$ 1,763,479	$ 2,154,430	$ 2,558,133	$ 2,974,587	$ 3,403,792	$ 3,863,101	$ 4,335,856	$ -	12	
13	Distribution - 97.87%	322,467	335,034	347,602	360,169	372,736	385,304	397,871	410,439	423,006	452,961	466,222	479,484	4,753,295	13	To: Pg 2, Col (d), Ln 9
14	Transmission - 2.13% (Demand Allocator 67.22% / 64.27%	4,726	4,910	5,094	5,278	5,463	5,647	5,831	6,015	6,199	6,348	6,533	6,719	68,764	14	To: Pg 2, Col (d), Ln 10
15															15	
16	2024 Total Capital Balance for Recovery	$ 327,193	$ 667,137	$ 1,019,833	$ 1,385,280	$ 1,763,479	$ 2,154,430	$ 2,558,133	$ 2,974,587	$ 3,403,792	$ 3,863,101	$ 4,335,856	$ 4,822,059	$ 4,822,059	16	
17															17	
18	**OMAG Costs**														18	
19	Beginning Balance	$ -	$ 4,311,201	$ 8,647,372	$ 13,008,656	$ 17,395,199	$ 21,807,148	$ 26,244,649	$ 30,707,851	$ 35,196,902	$ 39,711,952	$ 44,083,672	$ 48,463,872	$ -	19	
20	Distribution - 96.25%	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	4,125,591	49,507,091	20	
21	Transmission - 3.75%	160,785	160,785	160,785	160,785	160,785	160,785	160,785	160,785	160,785	160,785	160,785	160,785	1,929,424	21	
22	Subtotal	4,286,376	8,597,578	12,933,748	17,295,032	21,681,576	26,093,524	30,531,025	34,994,227	39,483,278	43,998,328	48,370,048	52,750,248	51,436,514	22	
23															23	
24	Carrying Charge Period 6 - Dist	23,894	47,926	72,098	96,410	120,862	145,456	170,193	195,072	220,096	82,142	90,304	98,482	1,362,936	24	
25	Carrying Charge Period 6 - Trans	931	1,868	2,810	3,757	4,710	5,669	6,633	7,602	8,578	3,201	3,519	3,838	53,117	25	
26															26	
27	Total OMAG - Distribution	4,149,485	4,173,517	4,197,689	4,222,001	4,246,453	4,271,047	4,295,784	4,320,663	4,345,687	4,207,733	4,215,895	4,224,072	50,870,026	27	To: Pg 2, Col (d), Ln 3
28	Total OMAG - Transmisssion	161,717	162,653	163,595	164,543	165,496	166,454	167,418	168,388	169,363	163,987	164,305	164,623	1,982,541	28	To: Pg 2, Col (d), Ln 4
29															29	
30	2024 Total OMAG Balance for Recovery	$ 4,311,201	$ 8,647,372	$ 13,008,656	$ 17,395,199	$ 21,807,148	$ 26,244,649	$ 30,707,851	$ 35,196,902	$ 39,711,952	$ 44,083,672	$ 48,463,872	$ 52,852,568	$ 52,852,568	30	
31															31	
32	**2024 Ending Balance for Recovery**	$ 4,638,394	$ 9,314,509	$ 14,028,489	$ 18,780,480	$ 23,570,627	$ 28,399,079	$ 33,265,984	$ 38,171,489	$ 43,115,745	$ 47,946,773	$ 52,799,728	$ 57,674,627	$ 57,674,627	32	
33															33	
34	**PERIOD 7 (2025 Cost Recovery)**														34	
35	**Account No. 182-3XX**														35	
36	**Capital Costs**														36	
37	Depreciation Expense	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 214,361	$ 2,572,335	37	
38	Return on Rate Base	380,089	403,366	426,642	449,919	473,195	496,471	519,748	543,024	566,300	589,577	612,853	636,129	6,097,314	38	
39	Subtotal	594,451	617,727	641,003	664,280	687,556	710,833	734,109	757,385	780,662	803,938	827,214	850,491	8,669,649	39	
40															40	
41	Beginning Balance	$ -	$ 589,919	$ 1,202,937	$ 1,839,053	$ 2,498,269	$ 3,180,584	$ 3,885,997	$ 4,614,509	$ 5,366,121	$ 6,140,831	$ 6,938,640	$ 7,759,548	$ -	41	
42	Distribution - 97.87%	581,766	604,546	627,326	650,105	672,885	695,665	718,444	741,224	764,004	786,783	809,563	832,343	8,484,654	42	To: Pg 3, Col (d), Ln 9
43	Transmission - 2.13% (Demand Allocator 64.27%)	8,153	8,472	8,791	9,110	9,430	9,749	10,068	10,387	10,706	11,026	11,345	11,664	118,901	43	To: Pg 3, Col (d), Ln 10
44															44	
45	2025 Total Capital Balance for Recovery	$ 589,919	$ 1,202,937	$ 1,839,053	$ 2,498,269	$ 3,180,584	$ 3,885,997	$ 4,614,509	$ 5,366,121	$ 6,140,831	$ 6,938,640	$ 7,759,548	$ 8,603,555	$ 8,603,555	45	
46															46	
47	**OMAG Costs**														47	
48	Beginning Balance	$ -	$ 5,110,792	$ 10,231,498	$ 15,362,136	$ 20,502,726	$ 25,653,287	$ 30,813,839	$ 35,984,401	$ 41,164,992	$ 46,355,632	$ 51,556,340	$ 56,767,136	$ -	48	
49	Distribution - 88.38%	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	4,498,716	53,984,591	49	
50	Transmission - 11.62%	602,182	602,182	602,182	602,182	602,182	602,182	602,182	602,182	602,182	602,182	602,182	602,182	7,226,184	50	
51	Subtotal	5,100,898	10,211,690	15,332,396	20,463,034	25,603,624	30,754,185	35,914,737	41,085,299	46,265,890	51,456,530	56,657,238	61,868,034	61,210,775	51	
52															52	
53	Carrying Charge Period 7 - Dist	8,726	17,469	26,229	35,006	43,800	52,612	61,440	70,285	79,148	88,027	96,924	105,838	685,505	53	
54	Carrying Charge Period 7 - Trans	1,168	2,338	3,511	4,686	5,863	7,042	8,224	9,408	10,594	11,783	12,974	14,167	91,759	54	
55															55	
56	Total OMAG - Distribution	4,507,442	4,516,185	4,524,945	4,533,722	4,542,516	4,551,327	4,560,156	4,569,001	4,577,863	4,586,743	4,595,640	4,604,554	54,670,096	56	To: Pg 3, Col (d), Ln 3
57	Total OMAG - Transmisssion	603,350	604,520	605,693	606,868	608,045	609,224	610,406	611,590	612,776	613,965	615,156	616,349	7,317,943	57	To: Pg 3, Col (d), Ln 4
58															58	
59	2025 Total OMAG Balance for Recovery	$ 5,110,792	$ 10,231,498	$ 15,362,136	$ 20,502,726	$ 25,653,287	$ 30,813,839	$ 35,984,401	$ 41,164,992	$ 46,355,632	$ 51,556,340	$ 56,767,136	$ 61,988,039	$ 61,988,039	59	
60															60	
61	**2025 Ending Balance for Recovery**	$ 5,700,711	$ 11,434,434	$ 17,201,189	$ 23,000,995	$ 28,833,871	$ 34,699,836	$ 40,598,910	$ 46,531,113	$ 52,496,463	$ 58,494,980	$ 64,526,684	$ 70,591,594	$ 70,591,594	61	
62															62	

SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY
2024-2026 NDPP 1st AMENDMENT
(IN DOLLARS)

Ln	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	Ln	
1	Carry Charge	6.95% effective 01/01/2023 to 09/30/2024				2.33% excluding equity component effective 10/01/2024									1	
2														Summary of	2	
3		January	February	March	April	May	June	July	August	September	October	November	December	Annual Activity	3	Reference
4															4	
63	**PERIOD 8 (2026 Cost Recovery)**														63	
64	**Account No. 182-3XX**														64	
65	**Capital Costs**														65	
66	Depreciation Expense	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 299,392	$ 3,592,700	66	
67	Return on Rate Base	659,406	680,218	701,031	721,843	742,656	763,468	784,281	805,093	825,906	846,718	867,531	888,343	9,286,493	67	
68	Subtotal	958,798	979,610	1,000,423	1,021,235	1,042,047	1,062,860	1,083,672	1,104,485	1,125,297	1,146,110	1,166,922	1,187,735	12,879,194	68	
69															69	
70	Beginning Balance	$ -	$ 951,488	$ 1,923,630	$ 2,916,426	$ 3,929,875	$ 4,963,979	$ 6,018,736	$ 7,094,147	$ 8,190,212	$ 9,306,930	$ 10,444,303	$ 11,602,329	$ -	70	
71	Distribution - 97.87%	938,339	958,707	979,075	999,444	1,019,812	1,040,180	1,060,549	1,080,917	1,101,286	1,121,654	1,142,022	1,162,391	12,604,376	71	To: Pg 4, Col (d), Ln 9
72	Transmission - 2.13% (Demand Allocator 64.27%)	13,150	13,435	13,720	14,006	14,291	14,577	14,862	15,148	15,433	15,718	16,004	16,289	176,633	72	To: Pg 4, Col (d), Ln 10
73															73	
74	2026 Total Capital Balance for Recovery	$ 951,488	$ 1,923,630	$ 2,916,426	$ 3,929,875	$ 4,963,979	$ 6,018,736	$ 7,094,147	$ 8,190,212	$ 9,306,930	$ 10,444,303	$ 11,602,329	$ 12,781,009	$ 12,781,009	74	
75															75	
76	**OMAG Costs**														76	
77	Beginning Balance	$ -	$ 5,372,703	$ 10,755,827	$ 16,149,393	$ 21,553,420	$ 26,967,930	$ 32,392,943	$ 37,828,478	$ 43,274,557	$ 48,731,199	$ 54,198,426	$ 59,676,257	$ -	77	
78	Distribution - 89.47%	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	4,789,170	57,470,043	78	
79	Transmission - 10.53%	573,131	573,131	573,131	573,131	573,131	573,131	573,131	573,131	573,131	573,131	573,131	573,131	6,877,575	79	
80	Subtotal	5,362,301	10,735,004	16,118,128	21,511,694	26,915,722	32,330,232	37,755,244	43,190,780	48,636,858	54,093,501	59,560,727	65,038,559	64,347,618	80	
81															81	
82	Carrying Charge Period 8 - Dist	9,290	18,597	27,923	37,266	46,628	56,008	65,406	74,823	84,258	93,711	103,182	112,672	729,764	82	
83	Carrying Charge Period 8 - Trans	1,112	2,226	3,342	4,460	5,580	6,703	7,827	8,954	10,083	11,215	12,348	13,484	87,333	83	
84															84	
85	Total OMAG - Distribution	4,798,460	4,807,767	4,817,093	4,826,437	4,835,799	4,845,179	4,854,577	4,863,993	4,873,428	4,882,881	4,892,352	4,901,842	58,199,806	85	To: Pg 4, Col (d), Ln 3
86	Total OMAG - Transmisssion	574,243	575,357	576,473	577,591	578,711	579,834	580,959	582,085	583,215	584,346	585,479	586,615	6,964,907	86	To: Pg 4, Col (d), Ln 4
87															87	
88	2026 Total OMAG Balance for Recovery	$ 5,372,703	$ 10,755,827	$ 16,149,393	$ 21,553,420	$ 26,967,930	$ 32,392,943	$ 37,828,478	$ 43,274,557	$ 48,731,199	$ 54,198,426	$ 59,676,257	$ 65,164,714	$ 65,164,714	88	
89															89	
90	**2026 Ending Balance for Recovery**	$ 6,324,191	$ 12,679,457	$ 19,065,819	$ 25,483,296	$ 31,931,909	$ 38,411,679	$ 44,922,625	$ 51,464,769	$ 58,038,130	$ 64,642,729	$ 71,278,586	$ 77,945,723	$ 77,945,723	90	
91															91	

NV ENERGY
2024-2026 NDPP 1st AMENDMENT
FORECASTED ANNUAL kWh SALES INCLUDING DOS CUSTOMERS

	(a)	(b)	(c)		
Ln				Ln	Reference
1				1	
2		NPC	SPPC	2	
3	2024	24,341,070,735	13,751,001,068	3	To: Pg 2, Col (c) & (d), Ln 16
4	2025	24,755,031,157	14,929,807,556	4	To: Pg 3, Col (c) & (d), Ln 16
5	2026	25,257,238,027	16,078,433,449	5	To: Pg 4, Col (c) & (d), Ln 16

EXHIBIT SHELTON-PATCHELL-DIRECT-3

NV Energy
Residential Monthly Typical Bill Impacts

Ln	(a) Year	(b) NPC	(c) SPPC	Ln
1				1
2		**Single Family Residential**		2
3				3
4	2024	$ 0.50	$ 3.18	4
5	2025	$ 0.65	$ 3.59	5
6	2026	$ 0.70	$ 3.68	6
7				7
8		**Multi-Family Residential**		8
9				9
10	2024	$ 0.31	$ 1.88	10
11	2025	$ 0.41	$ 2.12	11
12	2026	$ 0.43	$ 2.17	12

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CARY SHELTON-PATCHELL, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: December 17, 2024

Cary Shelton-Patchell

CARY SHELTON-PATCHELL

CERTIFICATE OF SERVICE

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY** in Docket No. 24-12016 upon all parties of record in this proceeding by electronic service to the following:

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DATED this 27th day of March, 2025.

<u>/s/ Caitlin Katzenbach</u>
Caitlin Katzenbach
Paralegal
Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy