PACIFIC GAS AND ELECTRIC COMPANY

2022 WILDFIRE MITIGATION PLAN UPDATE

SECTION 4.6

ATTACHMENT 1

(REDLINE VERSION)

PACIFIC GAS AND ELECTRIC COMPANY
2022 WILDFIRE MITIGATION PLAN
SECTION 4.6, ATTACHMENT 1

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Table PG&E-4.6-1 Attachment

In this attachment, we are providing more detailed information regarding the Remedies in Table PG&E-4.6-1 that remain open and have ongoing activities.

Section 5.1: Risk Assessment and Mapping

<u>Utility #</u>: *PG&E-21-02*

<u>Issue title</u>: *Lack of consistency in approach to wildfire risk modeling across utilities.*

<u>Issue description</u>: *The utilities do not have a consistent approach to wildfire risk modeling. For example, in their wildfire risk models, utilities use different types of data, use their individual data sets in different ways, and use different third-party vendors. Energy Safety recognizes that the utilities have differing service territory characteristics, differing data availability, and are at different stages in developing their wildfire risk models. However, the utilities face similar enough circumstances that there should be some level of consistency in statewide approaches to wildfire risk modeling.*

<u>Remedies required and alternative timeline if applicable</u>: *The utilities*[1] *must collaborate through a working group facilitated by Energy Safety*[2] *to develop a more consistent statewide approach to wildfire risk modeling. After Energy Safety completes its evaluation of all the utilities' 2021 WMP Updates, it will provide additional detail on the specifics of this working group.*

A working group to address wildfire risk modeling will allow for:

1) *Collaboration among the utilities;*

2) *Stakeholder and academic expert input; and*

3) *Increased transparency.*

<u>Response to PG&E-21-02</u>:

The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021 (Progress Report).

Energy Safety established an initial schedule of bi-weekly working group meetings, starting October 20, 2021 and running through January 19, 2022, on various risk-modeling related topics such as modeling components, algorithms, data and

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1 Here "utilities" refers to San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E or the Company), Southern California Edison Company (SCE), PacifiCorp, Bear Valley Electric Service, Inc. (BVES), and Liberty Utilities; although this may not be the case every time "utilities" is used through the document.

2 The Wildfire Safety Division (WSD) transitioned to the Office of Energy Infrastructure Safety (Energy Safety) on July 1, 2021.

impacts of other issues on modeling such as climate change and ingress/egress. However, based on input during the Wildfire Risk Modeling Workshop on October 5-6, 2021, as well as the first Working Group Meeting on October 27, 2021, Energy Safety subsequently issued a revised schedule and topics for the Working Group moving forward. A final version of the schedule and topics was posted on November 8, 2021, which included comments on the October 5-6, 2021 workshop. The current working group schedule is:

Cadence:

- 2021 – Meet every 3 weeks
- 2022 – Meet monthly (except February)

Meetings are scheduled for Wednesday afternoons for a length of three hours.

Topics:

2021	
10/27	Meeting Logistics; modeling baselines, alignment, and past collaboration
11/17	Fire consequence (drivers, meteorology/climatology, environment, and fuels data)
12/8	Likelihood of asset risk events and ignitions (data, inputs, and risk drivers relating to assets, faults/outages/ignitions)
2022	
1/12	Likelihood of vegetation risk events and ignitions (data, inputs, and risk drivers)
3/2	PSPS likelihood (data, inputs, and risk drivers)
4/6	PSPS consequence and reliability analysis and impacts (including potential safety issues, power quality impacts)
5/4	Modeling algorithms, including confidences (machine learning, weather modeling, fire behavior modeling)
6/1	Modeling components, linkages, interdependencies
7/6	Smoke and suppression impacts
8/3	Climate change impacts and ingress/egress
9/7	Finalize risk modeling guidelines

The utilities are collaborating through the working group with Energy Safety and stakeholders and have already dedicated and will continue to dedicate substantial time and resources to the working group. The utilities believe that there will be increased transparency for Energy Safety and stakeholders through the working group process.

On November 17, 2021 and December 8, 2021 meetings were held to discuss “Fire Consequence”, and “Likelihood of asset risk events and ignitions” respectively. Energy Safety provided an agenda before each meeting which listed discussion topics and tentative time allotments. The meetings followed the agenda in a “Question and Answer” discussion format with utility subject matter experts.

On January 11, 2022, Energy Safety postponed the working group session scheduled for January 12, and informed that the working group schedule would pick back up on March 2, 2022 with the topic of “Likelihood of vegetation risk events and ignitions”.

The utilities look forward to future sessions with Energy Safety and stakeholders to promote continued collaboration, incorporate additional expert input, and increase transparency in order to help better realize our shared goal of reducing wildfire and PSPS risks.

Utility #: PG&E-21-04

Issue title:

PG&E does not adequately justify the wind speed inputs it uses in its Probability of Ignition models.

Issue description: PG&E's Outage Producing Winds model finds a correlation between equipment failure and high wind speed. Despite the correlation, PG&E does not use peak wind speed as part of its input data set for its Equipment Probability of Ignition models. Instead, PG&E uses average wind speed. PG&E provides justification for its rationale in its Revision Notice Response; however inconsistencies remain between PG&E's approach and that of its peer utilities that use peak or near-peak wind speeds as part of their Wildfire Risk Modeling input data sets.

Remedies required and alternative timeline if applicable:

PG&E must:

1) *Demonstrate that it appropriately accounts for wind speed in its Probability of Ignition models' input data sets. This shall be handled both within the Working Group set up in PG&E-21-02, as well as an individualized report; and*

2) *Address discrepancies between its input data sets and those of peer utilities.*

Response to PG&E-21-04:

1) As PG&E explained in the Progress Report on pages 8-9:

> We agree that climate and meteorological factors are key to both asset failure prediction and the conditions that determine whether an ignition propagates to a wildfire. PG&E previously provided a detailed technical description in support of the treatment of wind in both the Probability of Ignition and Wildfire Consequence Models that are part of the 2021 Wildfire Distribution Risk Model (WDRM). PG&E believes that this detailed description explains and supports the current use of wind data sets in the 2021 WDRM.
>
> We understand that certain parties providing comments on the 2021 WMP believe that peak wind speed should be a key predictive factor in wildfire risk models. To be clear, we agree that peak wind speeds are a key contributor to failures, ignitions, and wildfires. However, peak wind speed data sets are not predictive in the current Probability of Ignition Models. The 2021 Revised WMP outlines the reasons why we believe this to be the case and ways in which the modeling teams continue to analyze and seek to improve the predictive power of the models with wind data. For more information see 2021 Revised WMP, pp 165-166.
>
> The key challenge is that it is difficult to predict the peak wind speed in a location in the next year. Moreover, it is not just predicting the peak wind speed but the probability that a wind speed will occur that will exceed the strength of trees and assets in a given location. In operational models, where a wind speed is provided by meteorological forecasts, an estimate of the probability of

failure can be derived based on fragility curves. This is the case with the Transmission Operability Assessment Model that is part of the operational PSPS models. Predicting the probability of failure given a forecasted wind speed is different than predicting the annual probability of failure because the forecasted wind speed for a given point in the future year is difficult to predict. In a sense, the Probability of Ignition Given Initiating Events Module is also a prediction of where the wind speeds will peak above normal and exceed the stresses that trees and assets have normally weathered. We look forward to participating in the Working Group established by Remedy PG&E-21-02 to further discuss how wind speeds are reflected in risk modeling.

Wind data is integral to all steps in our modeling from the probability of failure, probability of ignitions given the failure, and the wildfire consequence. Wind data is used differently, according to the purpose, structure, and data available in each of these modeling steps. PG&E continues to make improvements in modeling wind speed. In the 2022 WDRM v3 the likelihood of failure is estimated for each location/asset separately for each subset with annual/multi-year values suitable for use in annual/multi-year planning. Wind contributions include prevailing wind and dryness conditions and the count of days that experience extreme dryness and wind. Probability of an ignition given a failure is then estimated using the conditions at the time of each failure, including fuel moisture and wind, and is predicted daily and integrated across days into annual/multi-year values to produce likelihood of ignition. PG&E expects that the issue of the use of wind data in modeling will continue to be a topic of discussion in the Energy Safety Risk Modeling Working Group.

2) PG&E continues to collaborate with other utilities and stakeholders as part of the monthly Energy Safety risk modeling working group on this topic. We understand that the utilities have taken different approaches to the type of wind speed data used in risk models. PG&E agrees that investigating and discussing the type of wind speed data used in risk modeling should be a key area of focus for the joint utility working group established in Remedy PG&E-21-02, and we look forward to hearing from other utilities regarding the data they use and why they believe this data is the most appropriate data for risk modeling.

Utility #: PG&E-21-05

Issue title: Lack of PSPS consequence model at a circuit segment level.

Issue description: SCE and SDG&E both have functioning PSPS consequence models, while PG&E states that their PSPS consequence model is currently under development.[3] *PG&E is working collaboratively with other California utilities and will complete the task by the second half of 2021. However, PG&E does not describe any specific efforts or progress regarding the development of the PSPS risk model. The incorporation of PSPS consequence risk into the total risk reduction of a mitigation initiative is crucial to the decision-making framework*

Remedies required and alternative timeline if applicable: PG&E must provide:

1) *A detailed update on the functionality of its PSPS consequence model at a circuit segment level, and*

2) *Quantitative targets for any remaining work or future developments.*

Response to PG&E-21-05:

Since the Progress Report, PG&E has developed a PSPS Consequence Model at the circuit segment level. PG&E is now able to represent the PSPS consequence as granular as at the customer meter level and aggregate up to the system level. As part of this development, PG&E also updated the input data set to the 2021 PSPS historical lookback, which is based on PG&E's latest approved PSPS protocols.

In developing the PSPS Consequence Model, we were able to achieve the following milestones as shared in the Progress Report:

- October 2021: Finalization of 2021 Circuit Segment List
- November 2021: Finalization of 2021 PSPS protocol historical lookback
- December 2021: Overlay 2021 Circuit Segments and historical lookback
- January 2022: Finalization of PSPS risk scores at the circuit segment level

As of January 2022, PG&E is in the process of sharing the results with stakeholders and management to help validate the results of the model. Once validated and approved, PG&E plans to use this model to support the development of 2023+ workplans, especially for the undergrounding mitigation initiative, which would consider both risk reduction from wildfire and PSPS. PG&E anticipates updating the PSPS Consequence Model annually, subject to the timing and availability of either new PSPS lookback data and refreshed circuit segment designations.

3 2021 Revised WMP, p. 49.

<u>Utility #</u>: PG&E-21-06

<u>Issue title</u>: Insufficient transparency for modifications to Wildfire Risk Models and circuit segment prioritization.

<u>Issue description</u>: Revision Notice Critical Issue RN-PG&E-02 required PG&E to provide further justification of its shift in Circuit Protection Zone (CPZ) prioritization, including external validation and reviews. While PG&E provided the required justification within its response, it is critical for PG&E to continue to provide updates on its modeling efforts in order to maintain transparency between now and the 2022 WMP Update regarding its prioritization of circuit segments. Additionally, in its response to the Revision Notice, PG&E provided a third-party review of its 2021 WDRM. The third-party's analysis included recommendations for PG&E to improve its Wildfire Risk Models.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Provide an update on progress made on each of the third-party's recommendations;*

2) *Provide any and all updates to the explanation and timeline for how and when it intends to address the recommendations;*

3) *Provide an Excel spreadsheet detailing what changes have been made to its 2021 risk models since the submission of its 2021 WMP Update; and*

4) *Provide a description of any changes it has made to its circuit segment the prioritization as a result of changes to its risk model since the submission of its 2021 WMP Update.*

<u>Response to PG&E-21-06</u>:

Table PG&E-REMEDY-21-06-1 below was provided in the Progress Report and details each of the recommendations from the third-party validation of the 2021 WDRM v2 conducted by E3 and our response and timeline for response to E3's findings.[4] The table has been updated from the Progress Report for the 2022 WMP. As indicated below, PG&E has addressed each of the E3 findings. Thus, this remedy will be closed with the submission of the 2022 WMP.

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4 2021 Revised WMP, pp. 177-180, Table PG&E-Revision Notice-4.5-5.

TABLE PG&E-REMEDY-21-06-1:
2021 WDRM RECOMMENDATIONS

Finding	Update on Planned Response	Update on Timeline for Response
<u>Strengthen the critical link between experts and models.</u> Develop an informed decision-making process.	Document work processes and decision-making process. Developing workplan steps in Foundry platform. Initial workplan tools have been developed in the Foundry platform. Subject matter expertise and analysis have been used to develop effectiveness factors for risk mitigation values in the model.	Q3 2021 as part of 2022 WDRM v3 documentation. Model completion and documentation moved to Q4. This is now completed with the development of the 2022 WDRM v3. Note: Per the schedule outlined in 4.5.1(b), the 2022 WDRM v3 will be approved for use in Q1 2022 and be used in the 2023 WMP and workplans contained therein.
<u>Create a roadmap that gives future goals and ties the Risk Model to other models. Consider including:</u> A process to understand effectiveness of vegetation management (VM) and system hardening, and steps to feed this understanding back into the Risk Model for evaluation of mitigation measures. A plan to evaluate how changing trends in local and global weather patterns may impact areas of ignition risk.	Develop as part of 2022 WDRM v3. An initial view of planned future model features is outlined in the WMP in terms of the Maturity Survey. Building on this a more comprehensive roadmap that is planned to illustrate both improvements and connections within the risk-model “ecosystem”. No change.	Q3 2021 as part of 2022 WDRM v3 documentation. Model completion and documentation moved to Q4. Roadmap developed and approved by Wildfire Risk Governance Steering Committee on 12/15/2021.

TABLE PG&E-REMEDY-21-06-1:
2021 WDRM RECOMMENDATIONS
(CONTINUED)

Finding	Update on Planned Response	Update on Timeline for Response
<u>Include covariates that will provide 'direct line of sight' to the impact of risk mitigation measures.</u> Consider adding more data fields for equipment characterization.	A host of additional equipment data is being prepared for use in the 2022 WDRM v3. Some of these include pole loading, LiDAR (Light Detection and Ranging) data for vegetation as well as asset location. In addition, historical information on previous grid configurations and assets are being prepared to better inform modeling. LiDAR data and pole loading data have been added to the 2022 WDRM v3 along with a host of data improvements including but not limited to improved outage locational data, PSPS damages to ignition data, and LiDAR informed asset locational information.	Q3 2021 with final release of 2022 WDRM v3. Additional data fields were added to the models in August 2021. Models are currently drafts and will be reviewed and approved with documentation in Q4 2021. This is now completed with the development of the 2022 WDRM v3. Note: Per the schedule outlined in 4.5.1(b), the 2022 WDRM v3 will be approved for use in Q1 2022 and be used in the 2023 WMP and workplans contained therein.
<u>Explore more modeling methods to better support selected algorithms.</u>	In the development of the 2022 model(s), a number of alternative algorithms are under development with the assets, such as poles and transformers, as their failure characteristics might be less environmentally driven. The objective is to utilize the method that demonstrates the best predictive power. This is particularly true as models representing assets such as poles and transformers are developed as their failure characteristics might be less environmentally driven. The support structure (poles) and transformers models have been developed using a time-series approach that performs better than the MaxEnt algorithm for these assets. While the results of the two algorithms were comparable, the time-series approach demonstrated improved predictive performance.	Q3 2021 with final release of 2022 WDRM v3. Draft models were developed in September 2021. Models are currently drafts and will be reviewed and approved with documentation in Q4 2021. This is now completed with the development of the 2022 WDRM v3. Note: Per the schedule outlined in 4.5.1(b), the 2022 WDRM v3 will be approved for use in Q1 2022 and be used in the 2023 WMP and workplans contained therein.

TABLE PG&E-REMEDY-21-06-1:
2021 WDRM RECOMMENDATIONS
(CONTINUED)

Finding	Update on Planned Response	Update on Timeline for Response
<u>Conduct uncertainty analysis around consequence scoring.</u> At a minimum, show uncertainty in risk scores based on range around averages at each simulation location.	Working with Technosylva to incorporate statistical data from fire simulations into the spatial MAVF consequence values. Technosylva has provided statistical measures for results at each location.	Q3 2021 with final release of 2022 WDRM v3. Data was provided in July 2021. Model completion and documentation moved to Q4. This is now completed with the development of the 2022 WDRM v3. Note: Per the schedule outlined in 4.5.1(b), the 2022 WDRM v3 will be approved for use in Q1 2022 and be used in the 2023 WMP and workplans contained therein.

Section 5.2: Situational Awareness and Forecasting

Utility #: PG&E-21-07

Issue title: PG&E's Distribution Fault Anticipation (DFA) and Early Fault Detection (EFD) technology pilot outcome is lacking justification for the scope of installment.

Issue description: PG&E's pilot project was completed in 2020 for DFA and EFD technology with the determination to continue deployment. However, PG&E lacks details and performance metrics on the outcome and how PG&E made the decision to ramp up deployment to 600-800 circuits.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Provide details and performance metrics on the outcome of the 2020 DFA and EFD technology pilot program; and*

2) *Explain how the determination was made to increase deployments of DFA/EFD technology across HFTD areas.*

Response to PG&E-21-07:

Information regarding the two items described in this Remedy was provided in the Progress Report. PG&E currently plans to Install EFD technology in approximately 25 locations on two circuits, DFA technology at substations serving approximately 45 circuits in 2021-2022, and to complete strategic assessment for ongoing deployment by June 30, 2022.

Section 5.3: Grid Design and System Hardening

Utility #: PG&E-21-09

Issue title: Limited evidence to support the effectiveness of covered conductor.

Issue description: The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full understanding of its Long-Term (LT) risk reduction and cost-effectiveness. The utilities' current covered conductor pilot efforts are limited in scope[5] *and therefore fail to provide a full basis for understanding how covered conductor will perform in the field. Additionally, utilities justify covered conductor installation by alluding to reduced PSPS risk but fail to provide adequate comparison to other initiatives' ability to reduce PSPS risk.*

Remedies required and alternative timeline if applicable:

The utilities[6] *must coordinate to develop a consistent approach to evaluating the LT risk reduction and cost-effectiveness of covered conductor deployment, including:*

1) *The effectiveness of covered conductor in the field in comparison to alternative initiatives; and*

2) *How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.*

Response to PG&E-21-09:

The utilities have developed a joint response to this remedy[7].

Introduction:

In the November 2021 Progress Report, the utilities outlined the approach, assumptions, and preliminary milestones to enable the utilities' to better discern the long-term risk reduction effectiveness of covered conductor to reduce the probability of ignition, assess its effectiveness compared to alternative initiatives, and assess its potential to reduce PSPS risk in comparison to other initiatives. In this report for the 2022 WMP Update, the utilities provide an update on their progress for each of the sub-workstreams, added efforts, and plans for 2022.

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5 Limited in terms of mileage installed, time elapsed since initial installation, or both.

6 Here "utilities" refers to SDG&E and PG&E, SCE, PacifiCorp, BVES, and Liberty Utilities; although this may not be the case every time "utilities" is used through the document.

7 As each utility completes its review of their WMP leading up to their filing date, there may be changes in this report from previous utility submissions.

Overview:

As explained in the November 2021 Progress Report, the utilities believe that long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives) requires multiple sets of information that need to be compiled, assessed, and updated over time. Since the November 2021 Progress Report, the utilities have made progress on each of the following sub-workstreams:

- Benchmarking
- Testing / Studies
- Estimated Effectiveness
- Additional Recorded Effectiveness
- Alternative comparison
- Potential to Reduce PSPS risk
- Costs

The utilities have also initiated discussions with the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group (DRWG) to establish a peer-review process for estimating/measuring the effectiveness of covered conductor. The utilities have obtained additional information from benchmarking, the Phase 1 Testing Report (2022WMP_PGE_Section 4.6_Remedy 21-09_Atch01), initial subject matter expert (SME) assessments of effectiveness of alternatives compared to covered conductor, an initial unit cost comparison, and have collected the utilities' estimated and recorded methods and results of covered conductor effectiveness. Each of these efforts are described further below. The information and assessments continue to indicate covered conductor effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with past benchmarking, testing and utility estimates. The utilities plan to continue each sub-workstream in 2022 to obtain new test data, conduct further benchmarking, improve methods for estimating and measuring effectiveness, and further the alternative assessments and unit cost comparisons. Below, the utilities describe the progress made on each sub-workstream and steps planned to continue this effort in 2022.

Background:

Covered conductor is a widely accepted term to distinguish from bare conductor. The term indicates that the installed system utilizes conductor manufactured with an internal semiconducting layer and external insulating UV resistant layers to provide incidental contact protection. Covered conductor is used in the U.S. in lieu of "insulated conductor," which is reserved for grounded overhead cable. Other utilities in the world use the terms "covered conductor," "insulated conductor," or "coated conductor" interchangeably. Covered conductor is a generic name for many sub-categories of conductor design and field construction arrangement. In the U.S., a few types of covered conductor are as follows:

- Tree wire
  - Term was widely used in the U.S. in 1970s
  - Associated with a simple one-layer insulated design
  - Used to indicate cross-arm construction
- Spacer cable
  - Associated with construction using trapezoidal insulated spacers and a high strength messenger line for suspending covered conductor
- Aerial bundled cable (ABC)
  - Tightly bundled insulated conductor, usually with a bare neutral conductor

The current type of covered conductor being installed in each of the utilities' service areas is an extruded multi-layer design of protective high-density or cross-linked polyethylene material. In this report, "covered conductor" refers generally to a system installed on cross-arms, in a spacer cable configuration, or as ABC. Table PG&E Remedy 21 09-1, below, provides a snapshot of the approximate amount and types of covered conductor installed in the utilities' service areas.

TABLE PG&E-REMEDY-21-09-1:
COVERED CONDUCTOR TYPE AND APPROXIMATE CIRCUIT MILES DEPLOYED BY UTILITY

Utility	First covered conductor installation (year)	Type of covered conductor installed	Approx. miles of covered conductor deployed through 2021	Notes
SCE	2018	Covered Conductor	2,900	Includes WCCP and Non-WCCP
	Installed Historically	Tree Wire	50	
	Installed Historically	ABC	64	
PG&E	CC end of 2017, beginning of 2018	Covered Conductor	883	Primary distribution overhead only
	TW installed historically	ABC	3	
SDG&E	2020	Covered Conductor	22	
		Tree Wire	2	
		Spacer Cable	6	
Liberty	2019	Covered Conductor	9	
		Spacer Cable	2	
Pacificorp	2007	Spacer Cable	53	
Bear Valley	2018	Covered Conductor	20	

Workstream Scope:

The overall focus is on the long-term effectiveness of covered conductor to reduce wildfire risk and PSPS impacts in comparison to alternatives. The outcome of this workstream is not to determine the scope of covered conductor nor is this effort intended to compare system hardening decisions that utilities have made and will make. Instead, the outcome of this effort is intended to produce (and update over time) a consistent understanding of the effectiveness of covered conductor, in comparison with alternatives to mitigate wildfire risk at the driver level and to reduce PSPS impacts. Utilities can then use these improved sets of information in their decision making. As part of this effort, the utilities anticipate there will likely be lessons the utilities can learn from one another such as construction methods, engineering/planning, execution tactics, etc. that can help improve each utilities' deployment of covered conductor but this is not the focus of this workstream. Additionally, and as further described below, the costs of covered conductor deployment differ based on numerous factors including, for example, the utilities' covered conductor system design, types and amounts of structure/equipment replacements, topography, scale of deployment, resource availability and other operational constraints. This effort is not intended to compare nor contrast costs across all different variations and instead presents an initial high-level covered conductor capital cost per circuit mile comparison with descriptions of the factors that lead to higher or lower costs.

Benchmarking:

Each of the utilities' covered conductor programs have been informed by benchmarking. Benchmarking is a useful process to obtain insights, lessons learned, and continually improve performance. SCE, for example, previously researched covered conductor use in the U.S., Europe, Asia, and Australia. SCE benchmarked directly with 13 utilities abroad and in the U.S. and surveyed 36 utilities on covered conductor usage.[8] These efforts helped inform SCE's Wildfire Covered Conductor Program (WCCP). The utilities, as part of this joint working group, have conducted additional benchmarking. First, the utilities developed a survey consisting of 24 questions that focused on covered conductor usage, performance metrics, conductor applications, and system protection. The survey was then sent to approximately 150 to 200 utilities in the U.S. and abroad. To date, 19 utilities participated in the benchmarking survey[9] and are listed below.

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation

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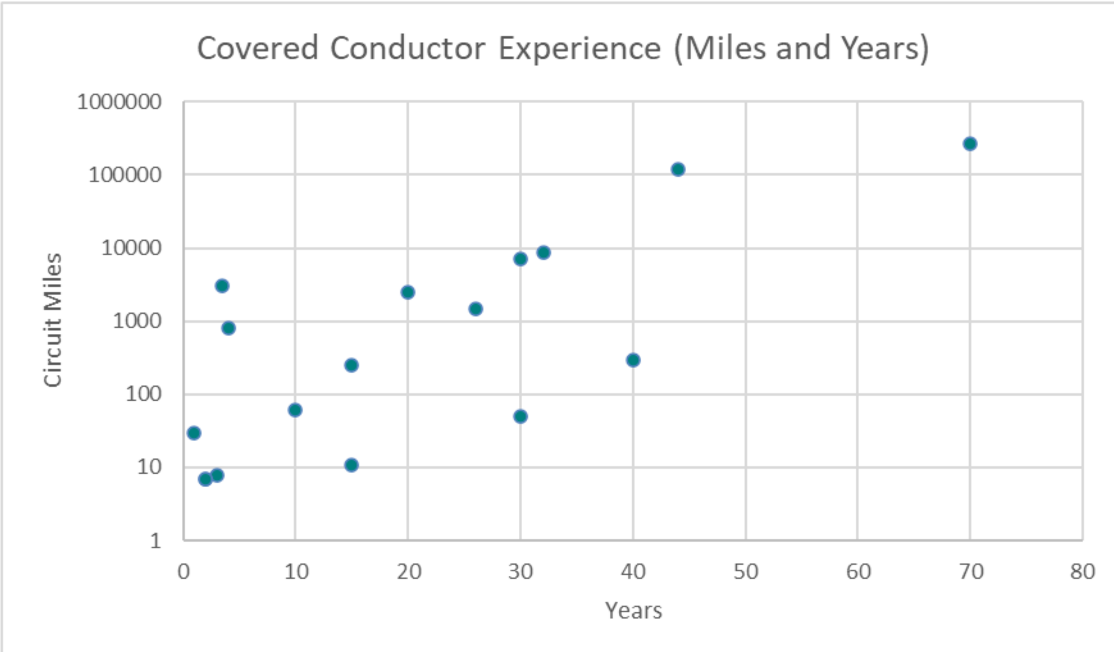
[8] See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.

[9] See 2022WMP_PGE_Section 4.6_Remedy 21-09_Atch02.

8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

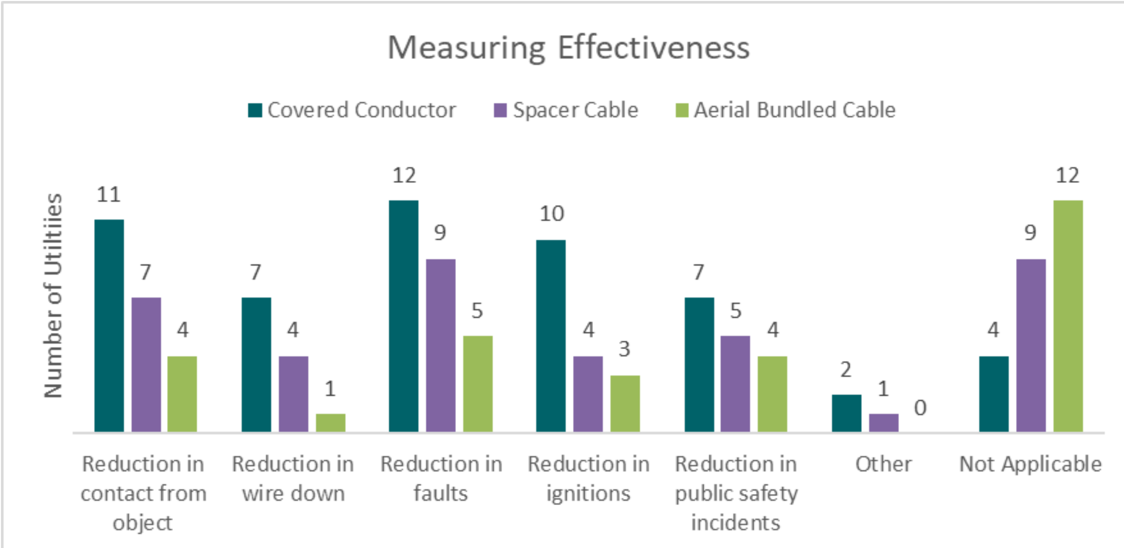
Approximately 90% of participants indicated the usage of bare conductor and covered conductor in their distribution systems. Respondents using spacer cable and aerial bundled cable were at 58% and 47%, respectively. Note that while covered conductor designs varied among the utilities, the majority (63%) of utilities use the three-layer jacket design. There was also a wide range of experience among respondents in terms of the number of years and miles installed, as shown in the Figure PG&E Remedy 21 09-1 below.

FIGURE PG&E-REMEDY-21-09-1:
COVERED CONDUCTOR (OPEN CROSSARM AND SPACER) EXPERIENCE AMONG RESPONDENTS



Drivers for covered conductor deployment can vary by utility. Typical drivers include wildfire mitigation, reliability improvements, or reduction in public safety risk for contact with downed conductors. The utilities' performance metrics will differ depending on their associated drivers. The majority of utilities base the covered conductor's effectiveness in its ability to reduce faults and ignitions from contact-from-objects (CFO). These metrics are related to reliability and wildfire mitigation. Some utilities also measure the reduction in wire downs and public safety incidents to measure the covered conductor's effectiveness, which can be connected to public safety risk or ignition drivers. Figure PG&E Remedy 21 09-2 illustrates the number of utilities using each metric to monitor the effectiveness of covered conductor, spacer cable, and aerial bundled cable.

FIGURE PG&E-REMEDY-21-09-2:
COVERED CONDUCTOR PERFORMANCE METRICS IN USE BY UTILITIES



While most utilities do not differentiate outages or ignitions between bare conductor and covered conductor, 84% of respondents reported that the use of covered conductor has reduced faults. Furthermore, 53% of respondents reported that covered conductor has reduced ignitions or ignition drivers. The remaining 47% of utilities do not track ignition data, had no prior ignitions, or do not have covered conductor in their system.

Approximately 80% of utilities reported undergrounding as an alternative to covered conductor. About 40% of utilities consider spacer cable while approximately 25% consider aerial bundled cable as alternatives to covered conductor. Typically, spacer cable is utilized in heavily-forested areas or areas with clearance concerns. Aerial bundled cable is normally indicated as used in heavily forested areas. Only 5% of utilities indicated the use of other alternatives, such as line removal/relocation, animal guard, fast isolation device, remote grid, customer buyout, and vegetation management.

In terms of fault detection, most utilities utilize traditional overcurrent protection. The same protection system that is used for bare conductors. Other existing fault detection methodologies include SCADA connected devices, smart meters, and high impedance fault detection. Utilities are also exploring a multitude of different technologies, including early fault detection (EFD), distribution fault anticipation (DFA), open phase detection (OPD), sensitive ground fault, rapid earth fault current limiter (REFCL), downed conductor detection, etc.

Overall, the benchmarking survey provides a high-level overview of each utilities' covered conductor deployment and performance metrics. In 2022, the California Investor-Owned Utilities (IOU) plan to conduct further deep dives with some respondents to gain a greater understanding of their covered conductor effectiveness, recorded data and methods they use to measure effectiveness, alternatives and new technology that have been evaluated, and their system hardening decision-making processes. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Testing:

Testing workstream objectives are to evaluate, through physical testing, the performance of covered conductors as compared to bare conductors for historically documented failure modes. As an example, testing covered conductor performance in preventing incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons.[10] To meet this objective, PG&E, SDG&E, and SCE collaborated on conducting additional research and testing of covered conductor. This effort, now joined by PacifiCorp, BVES and Liberty, has two phases. The first phase, which is now complete, had objectives to identify failure modes for covered conductors, document a utilities' consensus Failure Modes and Effects Analysis (FMEA) for covered conductors, and to collect all previously conducted testing on covered conductor performance that informs on the performance of covered conductor for identified failure modes. Lastly, to perform comparison between covered versus bare conductor performance for failure modes tested. PG&E contracted with Exponent, Inc. (Exponent) to develop a report for Phase 1, which was completed in December 2021, summarized below, and attached as Appendix B to this update. The Phase 1 study was led by Exponent and consisted of a literature review, discussions with SMEs, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. The outcome of the Phase 1 report identified gaps in previous testing and is informing the scope of laboratory testing that is currently being planned for in the ongoing Phase 2 step of this sub-workstream. As discussed below, SCE, PG&E, and SDG&E are proceeding with testing.

The literature review shows that covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently shows improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to covered conductor. The Phase 1 report includes data from several utilities that show a reduction of faults, increased reliability, and/or improvements in public safety metrics since the utilities began implementing covered conductor.

While high-level, field-experience-based evidence of covered conductor effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare and covered conductors. The workshop included SMEs from the six California IOUs and Exponent and identified hazards and failure modes applicable to bare and covered conductors. In total, 10 hazards and 55 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. Of the 10 hazards that affect bare conductors, covered conductors have the potential to mitigate six hazards. Mitigated hazards include tree/vegetation

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10 See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.

contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture. The report includes a risk reduction assessment of the failure modes that affect both bare and covered conductors. The report also summarizes failure modes mitigated by covered conductor. A total of 17 failure modes largely mitigated through the use of covered conductor were identified through the workshop exercise. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with covered conductors. Therefore, a corresponding reduction in ignition potential would be expected. The report also summarizes failure modes unique to covered conductor. Several covered-conductor-specific failure modes exist that require operators to consider additional personnel training, augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs, etc.). For some failure modes, the report recommends further testing to bolster industry knowledge and to enable more effective risk assessment.

SCE, PG&E and SDG&E are pursuing testing based on the results of the Phase 1 report and SME input. SCE established a test plan for both 17 kV[11] and 35 kV covered conductor designs and expects to conduct approximately 35 testing scenarios that cover various contact-from-object, system strength, flammability, and water ingress scenarios. PG&E is in process of developing a complementary test plan to ensure coverage of failure modes and additional covered conductor types that may not be included in the SCE test plan. SDG&E is assessing conducting, for example, environmental, service life, UV exposure, degradation and mechanical strength tests. The utilities are collaborating on the testing plans to ensure the gaps identified in the Phase 1 report are covered and SME input is considered.[12] SCE began testing on February 1 , 2022 and anticipates its testing and review process to extend for several months. SDG&E and PG&E timelines have not been finalized but are anticipating testing to start around Q2 to Q3 2022. The utilities will collaboratively review and assess the results of the tests. After the test results are reviewed and any issues are addressed (e.g., additional tests), the utilities will prepare a report (or reports in phases as testing is completed) and make the report(s) available. The test results are anticipated to further inform effectiveness of covered conductor and potentially identify any needed changes in design and construction standards to ensure failure modes are further limited by the use of covered conductor. Beyond the testing process, in 2022, the utilities will continue to collaborate on methods to quantify risk reduction of covered conductor relative to bare conductors taking into account the testing results and will establish any next steps for this sub-workstream based on the results of the testing. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

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11 SCE's 17 kV covered conductor design is the same as other utilities' 15 kV design. Through testing, SCE determined that the 15 kV design can withstand voltages below 17 kV so has named this covered conductor design 17 kV for operational purposes.

12 SCE, PG&E, and SDG&E are also collaborating on potential cost sharing.

Estimated Effectiveness:

Each utility's covered conductor programs are different due to factors such as location, terrain, and existing overhead facilities. Similarly, the utilities are at different phases of installing covered conductor as some have just started deployment while others have deployed hundreds to thousands of miles of covered conductor. These features, amongst others, result in data, calculations, and methods of estimating effectiveness that are different. As such, the utilities have been working on understanding differences and discussing methods for better comparability. While the utilities may differ in their covered conductor approach, the utilities each estimate that covered conductor will reduce wildfire risk. The utilities' estimated covered conductor effectiveness values range from approximately 60 to 90 percent at reducing outages/ignitions and/or the drivers of wildfire risk. Below, the utilities describe their data, analyses, and methods used to estimate the effectiveness of covered conductor to mitigate outages/ignitions and/or the drivers of wildfire risk and present their estimated effectiveness values. Collectively, the utilities summarize next steps to improve consistency of data, calculations and methods.

Covered Conductor Estimated Effectiveness:

SCE:

SCE's WCCP consists of replacing bare conductor with covered conductor, the installation fire-resistant poles (FRP) where applicable, wildlife covers (animal safe construction), lighting arresters, and vibration dampers below 3,000 feet. These activities are accounted for when determining the overall mitigation effectiveness of SCE's WCCP. To determine the mitigation effectiveness of WCCP, SCE evaluated the ability for covered conductor and FRPs to address each ignition risk driver. SME judgment was used to determine the mitigation effectiveness of covered conductor; this judgment was informed by benchmarking, analysis, and testing. The following tables explain the reasoning behind the effectiveness values. Table PG&E-REMEDY 21 09-2, below, includes only the covered conductor values and not the combined covered conductor and FRP values used in SCE's risk reduction calculation. Table PG&E-REMEDY 21 09-3, below, includes only the FRP mitigation effectiveness values. Additionally, mitigation effectiveness values at 0% or that were not applicable were omitted from both tables.

TABLE PG&E-REMEDY-21-09-2:
SCE COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Driver		Mitigation Effectiveness	Reasoning
D-CFO	Vegetation contact- Distribution	60%	SCE conducted analysis that involved establishing four vegetation sub-drivers based on SCE's experience with vegetation contact. The four sub-drivers are: Heavy Contact (Tree), Heavy Contact (Limb), Light Contact (Frond/Branch), Light Contact (Grow In). SCE analyzed historical vegetation fault data from 2015-2018 and determined that percentage of occurrence between all four sub-drivers. • Heavy Contact (Tree): 30% • Heavy Contact (Limb): 22% • Light Contact (Frond/Branch): 43% • Light Contact (Grow In): 5% SCE testing supported that covered conductor will be 99% effective against both Light Contact drivers, which accounts for 1% of the line potentially being uninsulated at connection points or dead-ends. Additionally, SCE also determined that covered conductor will not be effective against Heavy Contact (Tree) due to being unable to mechanically support the weight of a tree. Covered conductor was determined to be 50% effective against limb contact, conservatively assuming that the limb will exceed the conductor's strength 50% of the time. The overall mitigation effectiveness value for vegetation is based on the weighted average of all four sub-driver and was calculated to be 60%.
D-CFO	Animal contact- Distribution	65%	SCE conducted analysis that involved establishing animal contact sub-drivers in terms of equipment affected. These Animal Contact sub-drivers include Conductor/Wire, Fuse/BLF/Cutout, Terminations, Transformer, etc. The percent of animal contact faults were calculated per sub-driver using 2015-2020 data. Next, SCE used SME knowledge to establish the percent of wildlife covers existing in the system for the applicable sub-driver. Lastly, SCE assigned a preliminary mitigation effectiveness based on SME judgement per sub-driver. Covered conductor is considered 100% effective for Conductor/Wire Animal contact based on testing. Other equipment with

**TABLE PG&E-REMEDY-21-09-2:
SCE COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE
(CONTINUED)**

Driver		Mitigation Effectiveness	Reasoning
			associated wildlife covers were assigned a 90% effectiveness to account for the wildlife cover installation required during WCCP. The preliminary mitigation effectiveness was multiplied by the percent of wildlife covers not existing in the system to adjust for the possibility that pre-WCCP structures already have wildlife covers. The weighted average of this adjusted mitigation effectiveness was calculated to be 65%.
D-CFO	Balloon contact- Distribution	99%	Covered conductor is estimated to be 99% effective against contact with metallic balloons. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-CFO	Vehicle contact- Distribution	50%	SCE analyzed the composition of historical wire downs from vehicle collisions and found that nearly all ignitions from a vehicle collision are caused by conductor contact. SCE testing established the covered conductor is effective against conductor-to-conductor contact. However, there is uncertainty regarding the effectiveness of covered conductor during a wire down due to exposed conductor at the dead-end or break-point. To account for this uncertainty, a mitigation effectiveness of 50% was assumed.
D-CFO	Other contact-from-object - Distribution	77%	Analysis found that foreign material accounts for 77% of the “Unspecified” driver, while Ice/Snow accounts for the other 23%. While covered conductor is effective against foreign materials, it is not effective against ice/snow.
D-CFO	Connection device damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-CFO	Unknown contact - Distribution	77%	Weighted average of vegetation contact, animal contact, balloon contact, and other contact.
D-EFF[13]	Splice damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.

13 EFF represents Equipment/Facility Failure.

TABLE PG&E-REMEDY-21-09-2:
SCE COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE
(CONTINUED)

Driver		Mitigation Effectiveness	Reasoning
D-EFF	Crossarm damage or failure - Distribution	50%	Covered conductor is estimated to be 50% effective against crossarm failure. Reconductoring with covered conductor will facilitate the replacement of aged crossarms. Additionally, testing illustrated that covered conductor significantly reduced leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking.
D-EFF	Insulator damage or failure- Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.
D-EFF	Wire-to-wire contact / contamination- Distribution	99%	Covered conductor is estimated to be 99% effective against wire-to-wire contact. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-EFF	Conductor damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged conductor. Additionally, conductor failure due to faults will also be reduced because: (1) covered conductor will prevent contact-from-object faults from occurring and (2) the covered conductor will have a larger short circuit duty.
D-EFF	Insulator and brushing damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.

TABLE PG&E-REMEDY-21-09-3:
SCE FIRE RESISTANT POLE MITIGATION EFFECTIVENESS

Driver		Mitigation Effectiveness	Reasoning
D-EFF	Crossarm damage or failure - Distribution	50%	Replacing existing poles with FRPs will facilitate the replacement of aged wood crossarms with composite crossarms. Additionally, fire-resistant composite poles significantly reduce leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking. The improved crossarm design and reduction of leakage current accounts for the 50% effectiveness against crossarm damage or failure.
D-EFF	Conductor damage or failure — Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Fuse damage or failure - Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new fuses used will be improved technology.
D-EFF	Switch damage or failure- Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new switches may be improved technology.
D-EFF	Insulator and bushing damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Transformer damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new equipment may be improved technology (e.g., FR3 transformers).

PG&E:

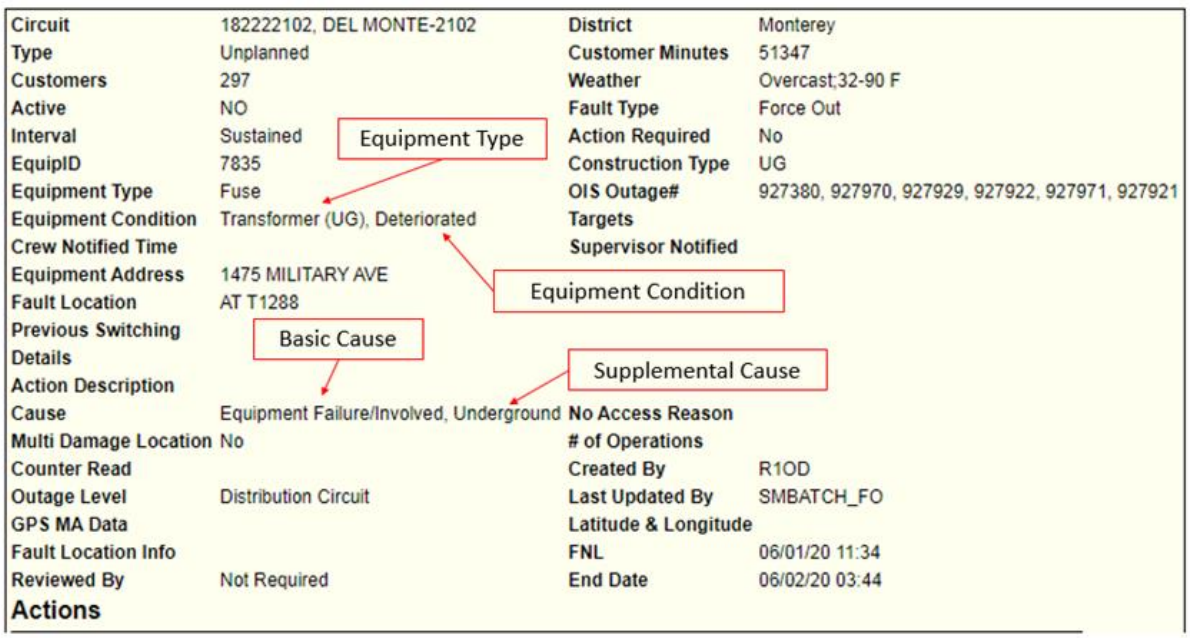
PG&E’s covered conductor program consists of primary and secondary conductor replacement with covered conductor along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers with transformers with FR3 insulating fluid, framing and animal protection upgrades, and vegetation clearing which makes up the entire Overhead Hardening program. PG&E understands the focus of this issue to be centered on covered conductor, however, PG&E’s efforts to estimate effectiveness extend to include all elements of its Overhead Hardening program as PG&E considers this approach more complete.

Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon the following proxy, outlined below, to derive its estimates. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2020 WMP as well as its 2020 RAMP filing.

With the above assumption, PG&E took the following approach to estimate a general effectiveness factor for overhead hardening:

1. SMEs identified 4,336 distinct outages by using all known combinations of basic cause, supplemental cause, equipment type and equipment condition from the distribution outage database as show in Figure PG&E-REMEDY 21 09-3 below. Whenever an outage is reported, an operator fills in different fields that provide information about the outage, through SME evaluation, it was decided that the combination of the four fields aforementioned provide an appropriate distinction of different outage types.

FIGURE PG&E-REMEDY-21-09-3:
PG&E DISTRIBUTION OUTAGE DATABASE RECORD



Circuit	182222102, DEL MONTE-2102	**District**	Monterey
Type	Unplanned	**Customer Minutes**	51347
Customers	297	**Weather**	Overcast;32-90 F
Active	NO	**Fault Type**	Force Out
Interval	Sustained	**Action Required**	No
EquipID	7835	**Construction Type**	UG
Equipment Type	Fuse	**OIS Outage#**	927380, 927970, 927929, 927922, 927971, 927921
Equipment Condition	Transformer (UG), Deteriorated	**Targets**	
Crew Notified Time		**Supervisor Notified**	
Equipment Address	1475 MILITARY AVE		
Fault Location	AT T1288		
Previous Switching Details			
Action Description			
Cause	Equipment Failure/Involved, Underground	**No Access Reason**	
Multi Damage Location	No	**# of Operations**	
Counter Read		**Created By**	R1OD
Outage Level	Distribution Circuit	**Last Updated By**	SMBATCH_FO
GPS MA Data		**Latitude & Longitude**	
Fault Location Info		**FNL**	06/01/20 11:34
Reviewed By	Not Required	**End Date**	06/02/20 03:44

Actions

2. SMEs identified whether overhead hardening would eliminate, reduce significantly, reduce moderately, reduce minimally, or will not have an effect on the likelihood of a certain type of outage occurring leading to an ignition when an asset has been hardened. From this classification the following qualitative categorization was performed:

   - All = Eliminates likelihood of a certain type of outage occurring resulting in an ignition

   - High = Reduces likelihood significantly of a certain type of outage occurring resulting in an ignition

- Medium = Reduces likelihood moderately of a certain type of outage occurring resulting in an ignition

- Low = Reduces likelihood minimally of a certain type of outage occurring resulting in an ignition

- None = Will not have an effect on likelihood of a certain type of outage occurring resulting in an ignition

3. Each of qualitative categories were assigned a quantitative value, which measured the likelihood of outage reduction:

    - All = 90%

    - High = 70%

    - Medium = 40%

    - Low = 20%

    - None = 0%

4. The above criteria were applied to historical outages, this resulted in likelihood of outage reduction for each outage.

5. Outages were classified by drivers, the outage drivers identified are: Animal, D-Line Equipment Failure, Human Performance, Natural Hazard, Other, Other PG&E Assets or Processes, Physical Threat, RIM, Third Party, Vegetation. The Wildfire Mitigation driver is excluded as this captures all PSPS triggered outages.

6. The final step in preparing the data was to add meteorology data that provides historical wind events times during the analyzed period 2015-2019, as well as weather signal data to allow for further analysis with meteorology experts.

7. A Pivot table is then created to aggregate Outages in HFTD that occurred during acute wind events days, this is understood to be the time where the equipment would be most stressed by the environment as well as the area where Overhead Hardening is being conducted. The aggregation is done at the outage driver level.

The results from the analysis detailed in the steps above are interpreted as Overhead Hardening having an effectiveness of approximately 63% for sections where Overhead Hardening has been completed. Therefore, a section of a line that has been hardened is approximately 63% less likely to have an outage of any type. Similarly, a section of a line that has been hardened is approximately 63% less likely to have an outage of each of the drivers. Below, Table PG&E Remedy 21 09-4 provides a summary of the results from the analysis.

TABLE PG&E-REMEDY-21-09-4:
PG&E COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Driver	Count of Incident ID	Average of Overhead Hardening Effectiveness percentage
Animal	36	76%
D-Line Equipment Failure	179	71%
Human Performance	3	0%
Natural Hazard	285	35%
Other	256	90%
Other PG&E Assets or Processes	15	47%
Third Party	20	62%
Vegetation	204	63%
Grand Total	998	63%

<u>SDG&E</u>:

SDG&E initially began to examine covered conductor from a personnel safety and reliability standpoint. The three-layered construction showed prospective reduction of injuries to people in the event of an energized wire-down in which the wire contacted a person and/or also might reduce the step potential to people in the vicinity. Outages that result from light momentary contacts (e.g., mylar balloons, birds, and palm fronds) also have shown the potential to be reduced. In late 2018, focus was shifted towards using covered conductor as an alternative to SDG&E's traditional overhead hardening program with the primary focus of reducing utility-caused ignitions.

SME's conducted research on the history and use of covered conductor in the industry. Additionally, the SMEs reached out to utilities on the East Coast and internationally to receive their feedback of the effectiveness and work methods for installation purposes.

In addition to other studies/tests that have been and will be performed by SCE and PG&E, as described in the Testing section, SDG&E will have a third party evaluate the likelihood and effect specific to conductors clashing at various wind speeds. Accelerated aging studies will also be performed to mimic a 40-year service life; after which, the samples will be subjected to tests designed to understand the potential for both mechanical degradation, as well as a reduction in the dielectric strength of the covering. These tests will be performed in accordance with ASTM or other industry recognized standards.

In order to quantify the risk reduction of wildfires that would be achieved by covered conductor, SDG&E evaluated 80 events that resulted in ignitions. SMEs weighed in on the likelihood that covered conductor installation would prevent an ignition for the particular type of outage depending on the severity of the incident. As seen in Table PG&E Remedy 21 09-4 below, the result is a reduction in ignitions from 80 to 28.4, and a resulting effectiveness estimate of 64.5%.

TABLE PG&E-REMEDY-21-09-5:
SDG&E COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Animal contact	5	90%	0.5
Balloon contact	8	90%	0.8
Vegetation contact	10	90%	1.0
Vehicle contact	14	20%	11.2
Other contact	4	10%	3.6
Other	2	10%	1.8
Equipment - All	34	80%	6.8
Unknown	3	10%	2.7
Total	80	64.5%	28.4

PacifiCorp:

PacifiCorp has some experience with installing a spacer cable system, which primarily includes covered conductor, a structural member (messenger), and specialized attachment brackets. The Company pursued this design due to historical experience with elevated outage count from trees, limbs, and incidental contact (resulting in grow in) throughout its service territory. Additionally, access conditions on some of its circuits are extremely difficult in certain times of the year, and those circuits also tend to have elevated outage rates. For the above-mentioned reasons, when siting its spacer cable pilot projects, PacifiCorp tended to focus its deployment on circuit-segments that had above average vegetation and/or animal outage rates in conjunction with difficult access.

Spacer cable systems employ an engineered weak-link system where covered conductors are in a spaced bundle configuration. The bundle is supported by a high-strength tensioned cable which has shown to be able to support the cables even when the system is under extreme stress.[14] This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. PacifiCorp's spacer cable systems are currently installed using components rated at or above 35 kV, where the only deviation is in the covered conductor itself, whereas it uses two voltage classes; 15 kV for energized voltages of 12.47 kV and below and 35 kV for energized voltages of 20.8 kV to 34.5 kV.

Originally contemplated as a reliability improvement tool, PacifiCorp has now moved to leveraging spacer cable as a wildfire mitigation tool; a natural progression given the

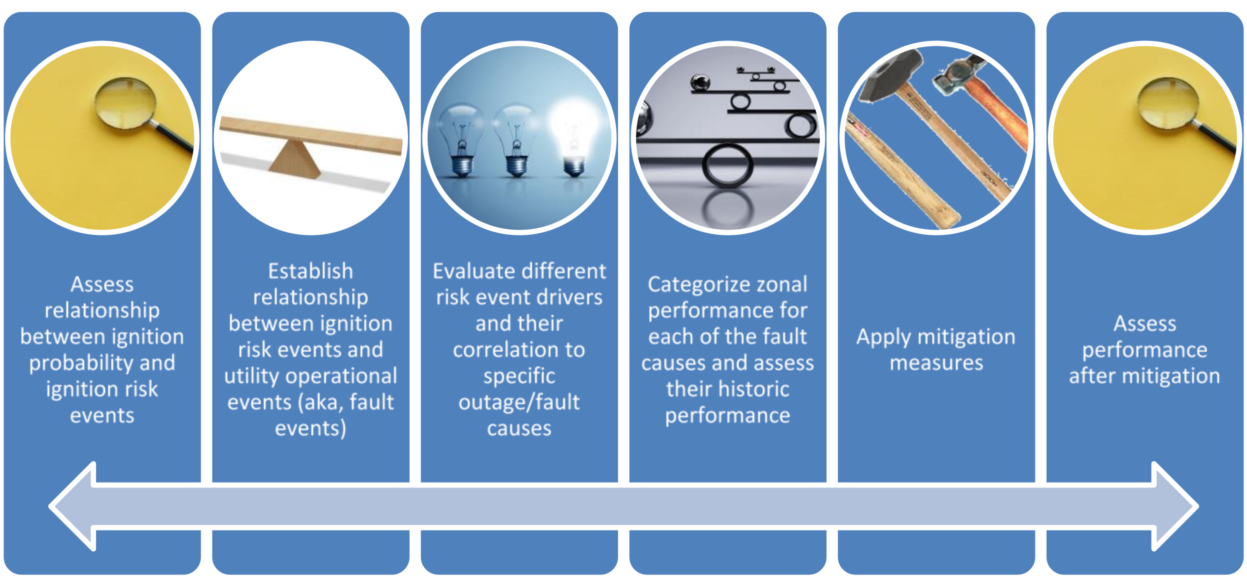
14 Bouford, James D. "Spacer cable reduces tree caused customer interruptions." 2008 IEEE/PES Transmission and Distribution Conference and Exposition. IEEE, 2008.

similarities in risk drivers such as contract-from-object or damage from vegetation. In their original installations, reliability improvement was the driver, but because of the newness of the technology it was trialed in several different environments with differing installation approaches; the first was focused on contact-from-object/animals and subsequently two of them were focused on contact-from-object/vegetation, one in a coastal environment and another in a mountainous environment, which was followed by projects heavily targeting mitigation of contact-from-object as well as blow-in (and other incidental vegetation); the projects formed the basis for targeting covered conductor (specifically spacer cable) as a mitigation measure for ignition risk drivers.

PacifiCorp's process for evaluating ignition risk drivers, mitigation measures and effectiveness of measures (in order to long term calculate risk spend efficiency) is detailed below.

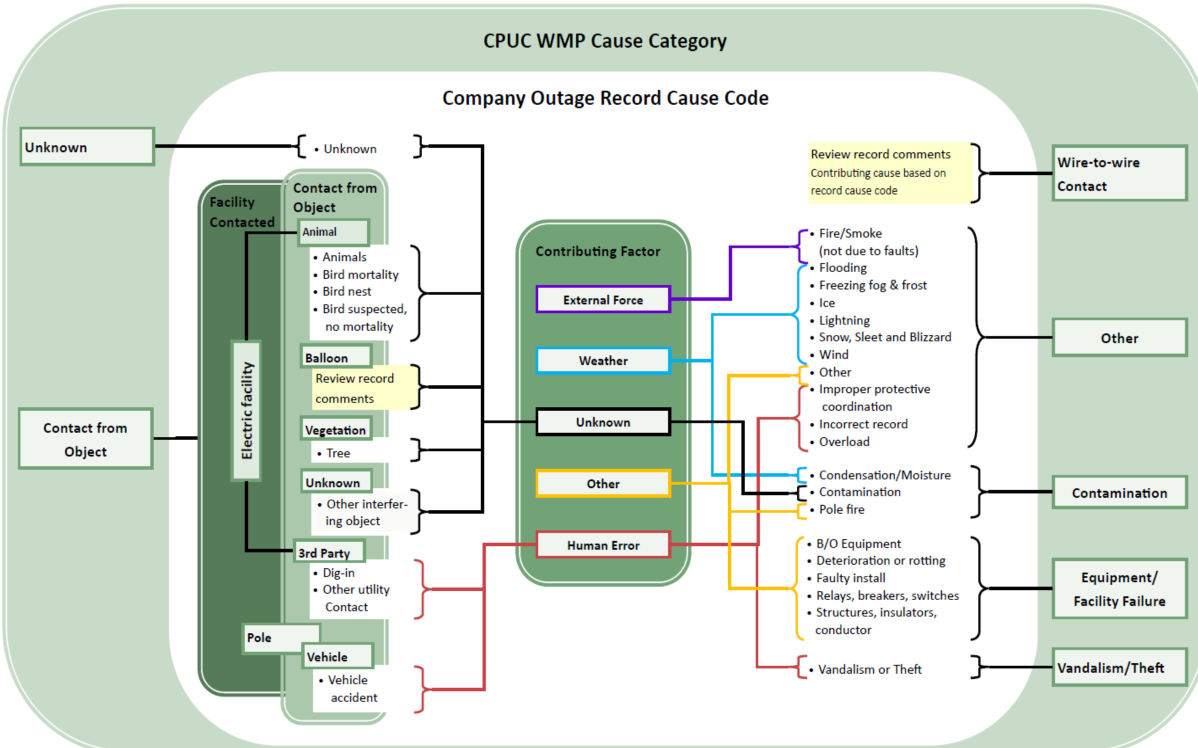
The Company prepared a mapping exercise to evaluate which risks could be addressed with what alternatives, recognizing that covered conductor and a variety of other measures might all be valid approaches. As a starting point, the Company evaluated its outage data to align against risk event drivers and correlating against mitigation alternatives. This process is shown graphically in Figure PG&E-REMEDY-21-09-4 below.

FIGURE PG&E-REMEDY-21-09-4:
PACIFICORP RISK MAPPING EXERCISE



With this process, as outlined below in Figure PG&E-REMEDY-21-09-5, PacifiCorp evaluated outage causes (and sub-causes, as well as commented information) to establish a relationship between forced outages and risk event drivers.

FIGURE PG&E-REMEDY-21-09-5:
PACIFICORP OUTAGE CAUSE EVALUATION



The Company then determined the average percentage of fire risk events and ignition events over the 2015-2020 period as shows in the figures below.

FIGURE PG&E-REMEDY-21-09-6:
PACIFICORP FIRE RISK EVENTS BY CAUSE CATEGORY

[INSERT FIGURE]

FIGURE PG&E-REMEDY-21-09-7:
PACIFICORP FIRE IGNITION EVENTS BY CAUSE CATEGORY

[INSERT FIGURE]

The Company then evaluated the probability (qualitatively scored and informed by the information above) of each ignition risk driver and its potential for ignition based on the season (fire and non-fire season) as shown in Figure PG&E-REMEDY-21-09-8 below. It was also segmented by transmission and distribution system, since the probabilities of each risk event driver and ignition risk were not equivalent. Qualitatively, PacifiCorp designated each cause either a low (L), medium low (ML), medium (M), medium high (MH), and high (H) by fire and non-fire season for the likelihood of the cause to result in an ignition to help establish priorities of mitigations.

FIGURE PG&E-REMEDY-21-09-8:
PACIFICORP FIRE RISK EVENTS ASSESSMENT

Risk Event Driver		Non-Fire Season		Fire Season	
		Transmission	Distribution	Transmission	Distribution
Wire down event (regardless of cause)		M	M	H	H
Contact-from-object	Veg. contact	M	M	H	H
	Animal contact	L	L	L	ML
	Balloon contact	L	L	L	ML
	Vehicle contact	L	ML	M	MH
	Other contact-from-object	L	L	L	ML
Equipment / facility failure	Connector damage or failure	M	M	H	H
	Splice damage or failure	M	M	H	H
	Crossarm damage or failure	L	L	M	ML
	Insulator damage or failure	L	L	L	ML
	Lightning arrestor damage or failure	L	M	L	H
	Tap damage or failure	L	L	L	ML
	Tie wire damage or failure	L	L	L	L
	Other	L	L	L	L
Wire-to-wire contact	Wire-to-wire contact / contamination	L	L	ML	M
Contamination		L	L	L	ML
Utility work / Operation		L	L	L	ML
Vandalism / Theft		L	L	L	ML
Other		L	L	L	L
Unknown		L	L	L	L

Based on PacifiCorp's spacer cable pilot projects, the Company is experiencing a 90% reduction in outage events. In order to evaluate this, PacifiCorp prepared pre-reconductor performance and contrasted it against post-reconductor performance and determined that the reduction in outages was approximately 90%. It is important to note that for these projects, since they were targeted specifically to environmental parameters that are visible (such as tree canopies or animal habitats), only the at-risk segments were reconductored (i.e., the entire zones of protection were not reconductored). The effect of this approach results in a high degree of confidence in the intended purpose of the project (against the specific risk driver). Should the measure be broadly extrapolated throughout the Company's system, in the areas where these risk drivers are not prevalent their effectiveness is more problematic to evidence, since a longer duration of the countermeasure must be in place to determine that it was in fact, effective. To further explain, if an area is not prone to a specific risk driver, a longer history is required to experience a given risk event.

In the future, as the Company reconductors entire zones of protection, it will have better certainty about the effectiveness of the mitigation against each ignition risk driver within that zone. For the initial projects, the scoping was directly motivated by reducing contact, primarily vegetation outage rates, and as a result the outage rates being measured are directly influenced by that decision. Even though the data is not perfect, it still provides a valuable insight into the expected reduction in risk from covered conductor. As the Company constructs more projects and as time passes for outage events to accrue, PacifiCorp expects to further refine the outage rate reduction by ignition risk driver. For the ignition risk drivers that it is not able to confidently measure, PacifiCorp takes the 90% reduction in outage rate and modifies it with SME input to create estimated effectiveness values. The ignition risk drivers, the estimated reduction, and the explanation is summarized in Table PG&E Remedy-21-09-6 below.

TABLE PG&E-REMEDY-21-09-6:
PACIFICORP COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Ignition Risk Driver	Estimated Effectiveness perc ent Reduction	Discussion
Vegetation Contact	90%	Vegetation contact is one of two primary drivers for the pilot project selection.
Animal Contact	90%	Animal contact is the second of two primary drivers for the pilot project selection.
Balloon Contact	99%	In general, expect contact from balloons to be mitigated.
Vehicle Contact	90%	Due to the increased strength of spacer cable systems, combined with increased resilience to wire-to-wire contact, estimate a 90% effectiveness.
Equipment Failure	90%	Much of the equipment used to construct bare overhead systems is replaced with different components. Additionally, phase conductors are not under tension. This estimated effectiveness is not incorporating downstream equipment such as transformers and protective devices.
Wire to Wire Contact	99%	Due to the forces experienced from vegetation contact, instances of wire-to-wire contact have been observed. No faults occurred.
Contamination	75%	Risk of contamination is estimated to be reduced due to systems being insulated beyond their standard NESC minimum ratings.
Vandalism/Theft	50%	In general, spacer cable has less risk of conductor theft as well as vandalism. Believe there are two areas where there could be increased risk of vandalism and theft, for example, damage from “gunshot” to the conductor covering, and theft of copper ground wiring.
Lightning	50%	Given spacer cables unique design where the messenger (neutral) is the topmost conductor, it acts as a grounded shield wire for the phase conductors. In addition, earth grounds are utilized every approximately 500 feet to further ground the system. With diligence in lightning arrester placement, estimate a 50% reduction in lightning-related faults.
Third Party	90%	Third-party including contact from joint use, boom arms, etc. should be mostly mitigated with spacer cable.

BVES:

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different types of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then BVES started the cover conductor Wildfire Mitigation Plan (WMP) late 2019 with a plan to cover 4.3 circuit miles on 34.5 kV over the next 5 years and 8.6 circuit miles on 4.16KV over the next 10 years. As of the end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV systems. BVES’ average span length is approximately 150 feet and installing covered conductor on cross arms with Hendrix insulators. As part of its covered conductor program when there are spliced locations, BVES installs premade cold shrink kits (3M) and installs avian protection (raptor protection/wildlife guard).

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor supplier, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%. This is BVES's first initial look and as it installs more covered conductor and gathers more historical data, it will continue to assess the estimate of effectiveness. BVES presents its estimated effectiveness in PG&E Remedy-21-09-7 below.

TABLE PG&E-REMEDY-21-09-7:
BVES COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Vegetation Contact	90% +	Vegetation contact on 1, 2, 3 phase and/or neutral wire.
Animal Contact	90% +	Animal contact on 1, 2, 3 phase and/or neutral wire.
Balloon Contact	90% +	Balloon contact on 1, 2, 3 phase and/or neutral wire.
Wire down contact	90% +	Due to the following: tree/tree limb fallen on line, car hit pole , wind gust, etc.
Vehicle Contact	90% +	Vehicle Contact due to wire down on vehicle.
Wire to Wire Contact	90% +	Due to the wind gust forces causing tree/tree limb to fall on line or just wire to wire contact.
Splice location contact	90% +	BVES installs Avian protection/raptor protection/wildlife guards and uses premade cold shrink kits (3M) on splice locations.
Vandalism/Theft	90% +	In BVES' service territory there is a low risk of conductor theft as well as vandalism. If vandalism occurs, Ex. damage from "gunshot" to the conductor covering installed.
Lightning Contact	90% +	During raining seasons, sometimes encounter a good amount of lightning strikes in BVES' service territory. BVES using priority covered conductor (flame resistant) cable.
Third Party	90% +	Third party including contact from joint use, boom arms, etc. should be mostly mitigated with covered conductor cable.
Flame Propagation along the covered conductor	90% +	Caused by Lightning or other.
Flame particle dripping	90% +	Caused by Lightning or other.

Liberty:

To estimate the effectiveness of its Covered Conductor WMP initiative in mitigating wildfire risk, Liberty evaluated the ability of covered conductor to reduce each ignition risk driver, as seen in TABLE PG&E Remedy-21-09-8 below. Liberty employed an internal risk working group to assess the effectiveness of covered conductor and other system hardening initiatives in reducing wildfire risk. This working group consisted of SMEs across its engineering, operations, wildfire prevention and regulatory teams. The SMEs convened weekly to discuss in detail each ignition risk driver and the mitigation effectiveness of covered conductor and other system hardening initiatives. SMEs referenced Liberty's historic outage data, including the location and cause of the outage and any associated dispatch or filed notes included in its outage management database. SMEs discussed the extent to which covered conductor would reduce, eliminate, or not have an effect on the likelihood of a specific type of outage occurring and leading to an ignition. Outages were classified by the ignition risk drivers listed in the table below and an estimated mitigation effectiveness percentage was developed for each risk driver.

The table below explains the reasoning for the estimated effectiveness values. Liberty continues to benchmark its evaluation within the industry. As Liberty continues to collaborate and benchmark with its peer utilities, including through the Joint IOU Covered Conductor Working Group, it will revisit the estimated effectiveness metrics and revise as necessary.

TABLE PG&E-REMEDY-21-09-8:
LIBERTY COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Vegetation contact	95%	CC will handle most tree branches falling on it, and grow-in, but not an entire tree (fall-in).
Vehicle contact	50%	If a car takes a pole out, there is a reasonable chance the circuit will remain in service. A wire-down event from car-hit-pole will result in fewer faults with covered conductor .
Conductor failure	80%	Conductor not totally fail-proof from branches (larger, heavier, falling further) or tree falls, potentially breaking poles and crossarms. Steel poles/fiberglass crossarms might mitigate some of this vs. wood.
Conductor failure - wire slap	95%	Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Conductor failure - wires down	80%	See logic for vehicle contact
Other - Including unknowns	75%	Liberty suspects that many ‘unknown’ OMS outage cause codes are non-failure wire slap, light veg contact, lightning or animal because no damaged component can be found as a reason for protective device operation.
Weather - Snow (better defined)	90%	Liberty’s covered conductor installation typically includes new poles and crossarms due to higher conductor loads. Poles designed to meet the GO 95 strength requirements.
Weather - Lightning	15%	Messenger wire on ACS attracts lightning strikes away from conductors.
Weather - Wind	90%	Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Pole Fire	80%	ACS prevents bare wire from laying on the cross-arm and burning. Tree wire has multi-layer jacket which greatly reduces opportunity for bare wire contact with wood supporting apparatus.

Next Steps:

As detailed above, the utilities estimate the effectiveness of covered conductor between approximately 60 and 90 percent. In 2022, the utilities will continue to meet on a regular basis to discuss estimated effectiveness methods, data and calculations. The utilities will learn from the benchmarking, testing, and recorded results and collaborate to improve each utilities' understanding and approach to estimate effectiveness. The utilities plan to discuss opportunities to align data and methods for greater comparability and will provide an update on these efforts in their 2023-2025 WMPs.

Recorded Effectiveness:

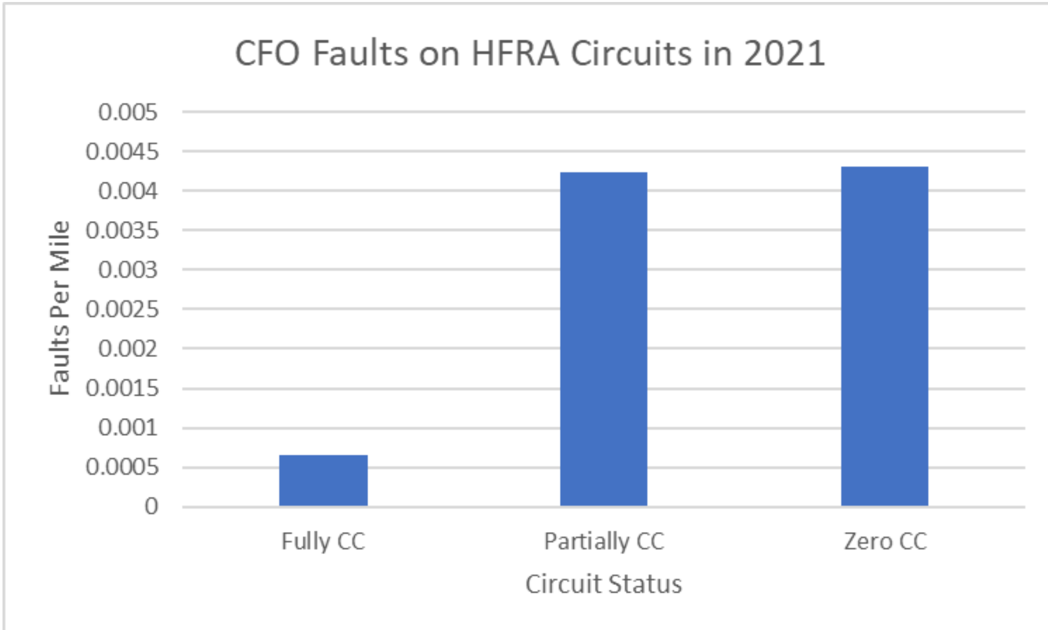
The utilities are in the early phases of covered conductor deployment and measuring its effectiveness. Though the utilities' data is limited, the early outcomes, as presented below, show covered conductor effectiveness at reducing the risk drivers that can lead to wildfires range between approximately 60 to 90 percent, which is consistent with the utilities' estimated effectiveness values, benchmarking, past testing results, and the results of the Phase 1 testing report (2022WMP_PGE_Section 4.6_Remedy 21-09_Atch01). With the limited amount of data and the fact that the utilities have taken different approaches to measuring the effectiveness of covered conductor, in 2022, the utilities will work towards developing a common methodology (or multiple methods) all utilities can use for better comparability. The utilities also plan to continue discussions with the IEEE DRWG on methodologies to measure the effectiveness of covered conductor as part of a peer-review process. Below, the utilities describe data and analyses they have conducted regarding measuring the recorded effectiveness of covered conductor and collectively the utilities summarize future steps to improve these methods and updates to the data sets.

Covered Conductor Recorded Effectiveness:

<u>SCE</u>:

SCE is measuring the overall effectiveness of covered conductor by comparing events (primary wire downs, primary conductor caused ignitions and faults) on fully covered circuits to bare circuits in its HFRA on a per-mile basis in current years. As of 2021, SCE's ire data does not show any events occurring on fully covered circuits. The data shows that circuits fully covered experience approximately 85% less or 15% of the faults caused by CFO then that of bare conductor do (see Figure PG&E-REMEDY-21-09-9).

FIGURE PG&E-REMEDY-21-09-9:
SCE FAULTS ON HFRA CIRCUITS IN 2021



As seen in the figure above, SCE is using current (2021) data by comparing results (e.g., faults per mile) in HFRA for circuits that have been fully covered, partially covered and not covered as opposed to historical data, which may either over- or under-represent the benefits by not capturing weather variations year after year and data quality improvements in identifying and tracking risk events.

Since 2018, SCE has documented known contact-related events with covered conductor. In one instance, a tree fell on covered conductor lines, making contact with all three phases. In another case, energized covered conductor lines fell into adjacent trees after a vehicle struck a pole, as shown in Figure PG&E-REMEDY-21-09-10 below. These events did not result in faults, wires down, or ignitions because covered conductor was deployed and provide examples of effectiveness of covered conductor in the field.

FIGURE PG&E-REMEDY-21-09-10:
COVERED CONDUCTOR CONTACT WITH VEGETATION AFTER CAR HIT POLE
OJAI, CALIFORNIA – JULY 24, 2020

PG&E:

To align with the estimated effectiveness approach, in 2021, PG&E started to analyze its hardened facilities' performance with regard to recorded outages, incidents, and ignitions so that it can continue to refine its strategy and improve the scope and design of its Overhead Hardening Program. PG&E will also analyze the performance of any hardened facilities that experienced a wildfire in order to validate assumptions about the life expectancy and effectiveness of hardened facilities in various conditions.

The Overhead Hardening Program is still in its infancy which makes it difficult to have the amount of data needed to have statistical significance from this type of analysis. Initial analysis has been limited to counts of outages at the circuit segment level that compare the annual average from 2015-19 (pre-overhead hardening) to the 2020 (hardened) total count of outages where overhead hardening was completed in 2019 as shown in TABLE PG&E Remedy-21-09-9 below.

TABLE PG&E-REMEDY-21-09-9:
PG&E PRE-OVERHEAD HARDENING COMPARED TO POST-HARDENED COUNT OF OUTAGES

2015-2019 Average Outage Count	2020 Outages	Change	Percent [Ave -2020] / Ave
591	225	-366	62%

While the calculated outage reduction percentage (used as a measure of recorded effectiveness) matches the initial 62% estimated effectiveness, the results are understood to be preliminary and lack the geospatial accuracy needed for a truly recorded effectiveness.

Additionally, PG&E considered including ignitions, and incidents such as a wire down, or PSPS incidents (damage / hazard) in hardened sections to enhance the measurement of effectiveness of the Overhead Hardening Program, however the data scarcity was even greater for a meaningful analysis.

Going forward, PG&E's focus is to find ways to better capture geo location of a fault, and, if applicable, the damage and broken equipment. Industry-wide, fault location has historically been assigned to the device operated and not necessarily the actual coordinates where a fault occurs. This improvement in the quality of spatial data guarantees a more precise analysis of areas where overhead hardening has been completed.

Lastly, PG&E remains committed to explore ways to best calculate effectiveness and has established a biannual monitoring cadence with its Wildfire Governance Steering Committee to ensure continued improvement. These efforts will be shared with this working group to continue to improve methods to measure the effectiveness of system hardening initiatives.

<u>SDG&E</u>:

SDG&E follows the same approach used to calculate the effectiveness of its Overhead Distribution Hardening, which is discussed in SDG&E's WMP in Section 4.4.2.3. SDG&E does not have sufficient data yet to draw any conclusions on the recorded effectiveness of covered conductor, as there is approximately only eighteen miles of covered conductor installed with an average age of less than one year. Across this small sample size, there have not been any faults on these covered conductor sections.

Moving forward, SDG&E will continue to track the mileage, years of service, and faults on all covered conductor circuit segments and will continue to collaborate with this working group to improve methods to measure the effectiveness of its system hardening initiatives. SDG&E's approach is to calculate the risk events per one hundred miles per year on segments that have been covered and compare the risk event rate before and after the installation of covered conductor.

<u>PacifiCorp</u>:

As outlined above, PacifiCorp tracks risk events (forced outages) within each zone of protection (ZOP) with known conductor types and assumes homogenous performance across the ZOP; current processes do not establish specific locations where fault events occur, but are reconciled to the device that protects the ZOP. To establish the recorded effectiveness, PacifiCorp queried pre- versus post-installation performance with risk event drivers for all ZOPs having covered conductor (specifically spacer cable construction). It was important to recognize that legacy projects were focused on reliability and thus did not require reconductoring of the entire ZOP. As such, the recorded effectiveness calculations accounted for the percentage of the ZOP that wasn't reconductored. The smaller the percentage of the ZOP the less the confidence of the recorded effectiveness, while the higher the percentage of the ZOP the higher the confidence of the calculation.

The table below shows the performance before and after covered conductor installation, with several of the more recent projects not yet having sufficient history to calculate the effectiveness. As such, the table below summarizes PacifiCorp's experience of about 15-20 miles of the total covered conductor installed.

FIGURE PG&E-REMEDY-21-09-10:
IMPROVEMENT PERCENTAGE FOR COVERED CONDUCTOR/SPACER CABLE PROJECTS

Project Circuit	Install Year	Pre Install Fault Rate (per Mile)	Post Install Fault Rate (per Mile)	Improvement %	Zone Spacer Cable After (%)
4W8	2018	0.11737	0	100	35.72
4W8	2018	0.80326	1.11155	-38.38	78.82
5A15	2017	0.15403	0.09387	39.06	27.67
5A93-1	2007	0.55552	0.35134	36.75	15.92
5A93-2	2017	0.85087	0.41872	50.79	16.1
5K50	2018	0.23498	0.10819	53.96	63.42
5L82	2013	0.55291	0.14227	74.27	100
5L82	2013	0.39609	0	100	100
5L82	2013	0.13227	0	100	66.19

This data is summarized graphically below in Figure PG&E-REMEDY-21-09-11, where the improvement percentage is compared against the percentage of the ZOP that was reconductored. As can be seen, the higher the percentage of the ZOPs, the higher the recorded effectiveness when measured by faults (risk events) per mile.

FIGURE PG&E-REMEDY-21-09-11:
PERCENTAGE OF COVERED CONDUCTOR (SPACER CABLE) IN ZONE VERSUS IMPROVEMENT PERCENTAGE

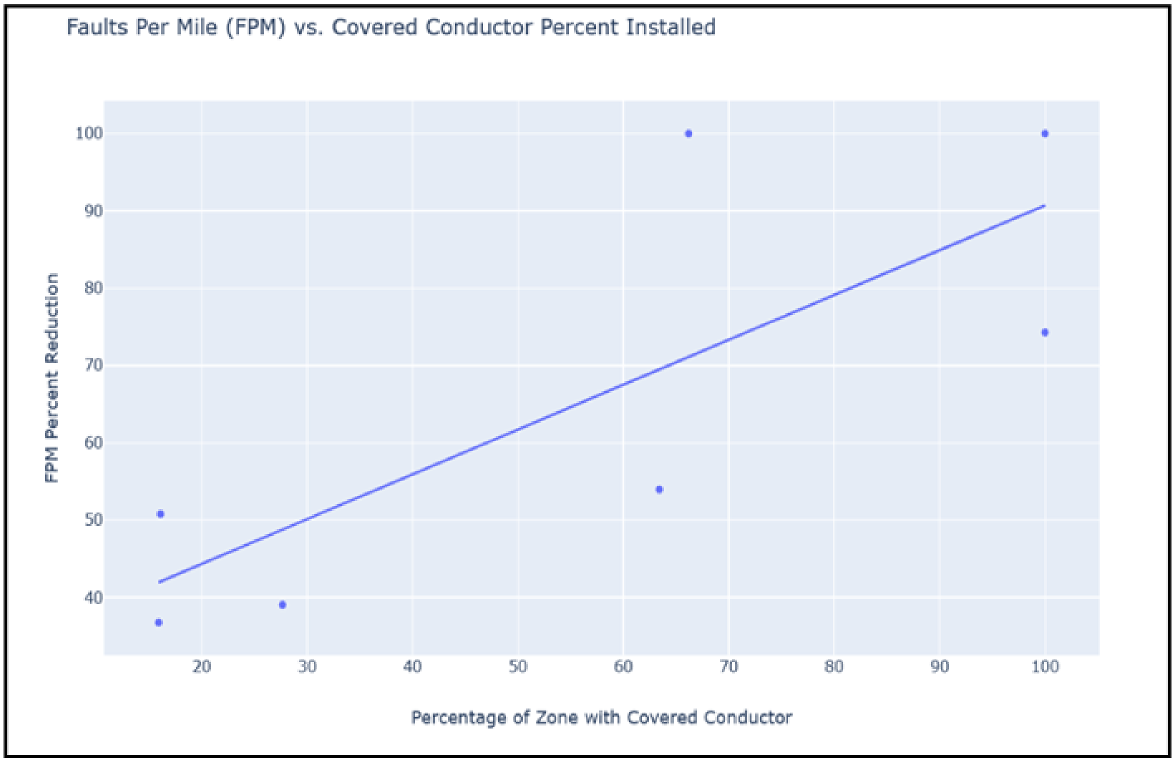
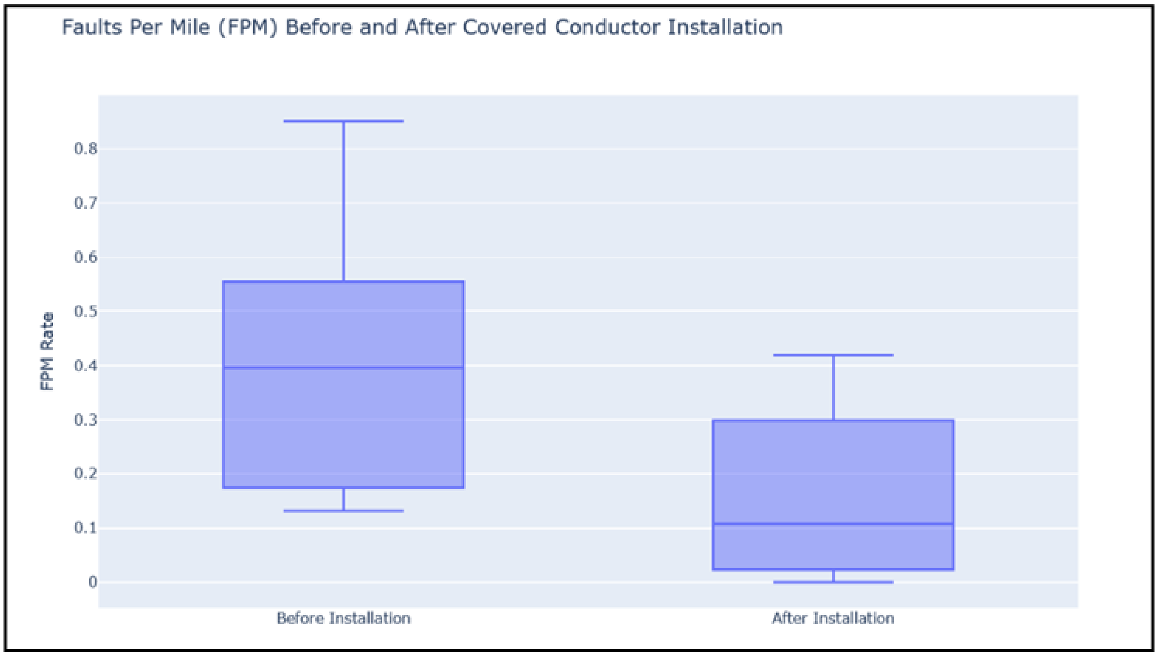


Figure PG&E-REMEDY-21-09-12 below shows how the ZOPs performed before the mitigation was completed versus after the mitigation was completed, normalized based on the faults-per-mile recorded.

FIGURE PG&E-REMEDY-21-09-12:
COMPARISON OF FAULTS PER MILE PERFORMANCE BEFORE VERSUS AFTER COVERED CONDUCTOR (SPACER CABLE) INSTALLATION



PacifiCorp has also documented known contact-related events with covered conductor. As shown in Figure PG&E Remedy 21-09-13 below, these events did not result in faults, wires down, or ignitions because spacer cable was deployed and provide examples of effectiveness in the field.

FIGURE PG&E-REMEDY-21-09-13:
EXAMPLES OF EFFECTIVENESS OF COVERED CONDUCTOR TO RISK EVENTS

BVES:

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different type of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then, BVES started the cover conductor WMP late 2019 with planning on covering 4.3 circuit miles on 34.5KV next 4 years and 8.6 circuit miles on 4.16KV next 10 years. As of end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV system.

In Q3 2018, BVES started a new tree-trimming contract with a new tree service contractor. BVES has been very aggressive with its vegetation manage program having up to four tree crews or more at a time to complete its three-year cycle and remediating any issue trees which has helped reduce outages from vegetation contacts.

As part of its WMP, in June 2019, BVES began replacing all expulsion fuses in its service area with Trip Savers and Elf Fuses. BVES completed this project in May 2021, which eliminated the potential for ignitions from expulsion fuses.

Currently, BVES has not had any outages, wire down, tree limbs and/or ignitions on the lines that have been covered. BVES is still in the early stages of its covered conductor program. As more areas are covered and as more time passes, BVES will be able to compile more recorded data to inform on the effectiveness of covered conductor. TABLE PG&E Remedy-21-09-11 below provides a simple assessment of recorded outages since 2016 in BVES' system which shows a reduction of outages beginning in 2019.

TABLE PG&E REMEDY-21-09-11:
BVES 2016-2021 RECORDED OUTAGES ASSESSMENT

BVES, Inc.	12/10/2021
Year	# of outage
2016	163
2017	256
2018	118
2019	61
2020	84
2021	65

Liberty:

Liberty's covered conductor program is relatively new, with the only significant projects being completed in 2020 and 2021. Because the program is new, data on the performance of covered conductor effectiveness will not yet demonstrate meaningful results based on the limited sample period and the wide variations in weather conditions. In addition, the covered conductor projects completed thus far represent a small percentage of each circuit and the outage data has only been evaluated on a circuit by circuit basis.

As an example, Liberty's Topaz 1261 circuit has 3.17 miles of covered conductor installed on the circuit which consists of an overall length of 55.6 miles. The illustrative table below shows historic 5-year forced outage data by outage risk driver for the Topaz 1261 circuit. As discussed in the Estimated Effectiveness working group section, Liberty identified significant outage risk drivers that could be mitigated with covered conductor and will use those outage risk drivers in its assessments of the effectiveness of its covered conductor projects. Liberty's forced outages on the Topaz 1261 circuit for 2021 are lower than the historic 5-year average. However, there were more forced outages in 2021 with a tree cause compared to previous years. In 2021, there were no outages recorded with wire slap as the cause, but there are only two recorded wire-slap causes in the study period. This example demonstrates that Liberty needs additional data to draw valid conclusions.

TABLE PG&E-REMEDY-21-09-12:
HISTORIC FORCED OUTAGES BY RISK DRIVER FOR TOPAZ 1261 CIRCUIT (2017 2021)

Outage Risk Driver	Historical Average (2017-2020)	2021
Wind/Flying Debris	2.5	1
Hardware/Equipment Failure	4	4
Vegetation	1	4
Deterioration	1	0
Wire Down	0.5	0
Animal	0.5	0
Wire Slap	0.5	0
Wildfire	0.25	0
Fire on Company Equipment	0.25	0
Total for Risk Drivers Listed	10.5	9

While Liberty's outage management system does provide five years of useful historic forced outage data by geospatial location, the following are data limitations that Liberty has identified and is working to improve:

- Only the approximate outage locations are documented by field crews. While the general area affected is valuable for evaluating performance, Liberty is working with its field crews to document location at a more specific level.

- There are limits to the way dispatchers code outages within Liberty's existing outage management system (OMS). Liberty is currently undergoing an upgrade to its OMS and is working with its operations, dispatch and engineering teams to improve the data and to identify outage metrics and risk drivers to include in the upgrade.

- The planned OMS upgrade will coincide with a budgeted GIS upgrade, closely followed by a budgeted AMI implementation. These combined implementations are expected to better capture cause documentation, geo location of faults, outage extent/duration, and protective device operation.

Next Steps:

In 2022, the utilities will continue to discuss methods of measuring the effectiveness of covered conductor, document the risk events and data utilities track, and work towards developing common methods to measure the effectiveness of covered conductor for better comparability. Since each utility has different processes and technical systems related to the collection of outage data, the utilities will work towards aligning on common methods. Of particular concern is ensuring a method or methods that all utilities can employ given the complexity in interruption data and differences in, for example, outage management systems, communication technologies, business practices, and causation identification and reporting. Methods the utilities plan to discuss include, for example, measuring faults in HFRA per hundred circuit miles per year comparing results pre- and post-covered conductor installation. Other methods include, for example, measuring the number of faults experienced in the current year for circuits that have been covered and circuits that have not been covered in HFRA and other metrics to demonstrate ignition performance. This will require SME discussions and review of outage, wire-down and ignition data across the utilities. The utilities also plan to refresh its data sets and discuss any incidents, trends, anomalies, etc.

Alternative Comparison:

The utilities identified an initial list of viable alternatives to covered conductor and conducted workshops with SMEs from the six utilities to assess the effectiveness of these alternatives against the same risk drivers that covered conductor is designed to mitigate. A viable alternative is a mitigation or group of mitigations that would address, to a similar or greater degree, the risk drivers that covered conductor is designed to mitigate. The utilities also included existing and a new bare conductor system as part of this assessment. The utilities used the risk drivers in Energy Safety's non-spatial data requirements (specifically, the non-repeated distribution causes and sub-cause categories in the WMP Guidelines, Table 7.1) to conduct the assessment. Below, the utilities describe the covered conductor system and alternatives that were selected for this assessment, the general assumptions that were applied, present the results of its assessment including descriptions of the factors that lead to lower or higher effectiveness, and describe the additional analyses the utilities plan to perform in 2022 to further the utilities understanding of the effectiveness of covered conductor compared to alternatives.

Covered Conductor System:

A covered conductor system generally refers to installing a conductor that is covered, replacing equipment/components that are required because of the covered conductor, such as insulators, cross arms, or poles (where applicable), replacing other equipment that is determined to reduce risk, improve resiliency/reliability and/or are cost-effective, and adding other protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

In very limited situations, it may be possible to simply re-string bare conductor with covered conductor. These limited situations would require all existing poles to withstand the heavier covered conductor and where polymer insulators are already in place. Simply re-stringing covered conductor would be a rare occurrence as it is not usually possible. As such, the utilities are comparing the relative effectiveness of alternatives to a covered conductor system, as described above, in their ability to reduce the risk drivers of ignitions.

Some of the risk drivers, such as Animal Contact, cannot be fully mitigated with covered conductor by itself. For example, you may also mitigate Animal Contact on a bare wire system by installing, wider crossarms (to increase the phase spacing) and coverings on jumper wires and at device connections. This presents some challenge in estimating the effectiveness of a system since it's not simply the covered conductor itself, but rather the combined mitigations working together to mitigate any given risk driver. As such, the utilities assumed that all overhead conductor-related alternatives include animal covers except the existing bare conductor system that is essentially a "do nothing" alternative.

Alternatives:

Below, the utilities describe the alternative mitigations that were compared with a covered conductor system.

Existing Bare Conductor System (status quo)

Existing systems, with enhanced maintenance activities and advanced system protection measures can be viewed as an alternative for covered conductor depending on the specific locational risk within the specified area. For purposes of this assessment, the utilities assumed a "do nothing" scenario regarding any system hardening upgrades. In the analysis below, this is labeled as Existing Bare Conductor. While the six utilities may have different existing overhead bare conductor systems in their HFRA, the utilities generally assumed existing bare conductor systems

<u>New Bare Conductor System (like-for-like replacement)</u>

This involves re-conductoring existing bare systems with like-for-like replacement of bare conductor, crossarms, connectors, etc. and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment. This type of system can reduce wire downs by mitigating conductor failures caused by fault current surpassing the ampacity threshold the conductor was designed for. However, this system will still be vulnerable to contact-from-object risk, wire slap, and some types of equipment failure.

Upgraded and Fire Hardened New Bare Conductor System (stronger conductor tensile strength, increased spacing, and stronger/taller steel poles)

This alternative is patterned after SDG&E's original fire hardening of its 69 kV transmission and 12 kV distribution systems located in its HFRA. SDG&E evaluated years-worth of reliability data in which one of the findings was that small wire conductor, #4 AWG and #6 AWG, was a significant driver for risk-related events. This information, coupled with the increased awareness of localized wind speeds in high risk areas, led to design changes of how these lines were constructed. The minimum size of the conductors was increased for additional tensile strength in addition to sometimes using dual steel core for support instead of single steel core. Under the previous design standards, lines were constructed to withstand working loads under stress of 56 mph wind speeds. The new design standard was able to withstand higher wind speeds, in some cases 85 mph and even up to 111 mph in specific cases. In addition to upgrading the conductor, wood poles were replaced with steel poles and increased phase spacing was used to minimize the potential of wire slap or phase-to-phase and phase-to-ground contacts.

Spacer Cable System

The spacer cable system utilizes a diamond shaped spacer to support covered conductor in a spaced bundle configuration, a high-strength messenger wire using a weak-link design concept, wherein the poles are the strongest member of the system, with the messenger the next strongest, and specialized attachment brackets that are the least strongest, such that if an impact load is experienced on phase conductors or poles, the system remains intact, but that "fails" the attachment of the bracket to the pole allowing for it to be quickly reattached. This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The utilities generally assumed poles would be replaced with stronger steel and/or fire-resistant poles to support this system. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. The high-strength messenger wire provides greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Aerial Bundled Cable System

An Aerial Bundled Cable (ABC) system consists of one, two, or three individual cables that are fully insulated. The cables are wrapped together and, similar to a spacer cable system, supported by a high-strength messenger with a lashing wire. Because the cables in ABC are fully insulated, ABC can withstand continuous contact-from-objects for an indefinite time period. The high-strength messenger also provides the ABC system with mechanical protection from objects falling onto the line. For purposes of the assessment, the utilities assumed the ABC would be installed using stronger structures that combined with the high-strength messenger would provide greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Underground System

An underground system consists of underground cable (e.g., crosslinked polyethylene cable (XLPE) installed in PVC conduit), above-ground pad-mounted equipment (e.g., transformers) or equipment in vaults, cable terminations and joints, surge arrestors and grounding electrodes. Underground cable can be direct-buried, direct-buried in conduit, or encased in concrete. For purposes of this assessment, the utilities generally assumed an undergrounded system with above-ground pad-mounted equipment and the cable/conduit encased in concrete. Undergrounding of electric infrastructure can significantly reduce wildfire risk and potentially reduce the need and frequency for PSPS outages. Additional potential benefits of undergrounding include an increase in service reliability, especially during wind events, and the reduction of the need for vegetation management work, and in general, improved public safety. An underground system can take significantly longer to complete and is more costly to construct as compared to other system hardening alternatives. An underground system can also be very complex to construct taking into account, for example, topography, geology, environmental or culture considerations, and land rights. In some instances, it is infeasible to construct.

Remote Grid

This alternative is patterned after PG&E's Remote Grid program designed to remove long feeder lines and serve customers from a Remote Grid. A "Remote Grid" is a concept for utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery, in lieu of traditional wires, to small loads, in remote locations, at the edges of the distribution system. As an example, in PG&E's service area there are pockets of isolated small customer loads that are currently served via long electric distribution feeders, some of which traverse HFRA and require significant annual maintenance, vegetation management, or system hardening solutions. The reduction in overhead lines as these Remote Grids are built can reduce fire ignition risk as an alternative to, or in conjunction with system hardening and other risk mitigation efforts. The utilities generally assumed in its assessment the differences between either covering a long distribution feeder line or eliminating the long distribution feeder line and installing a Remote Grid. The utilities did not include in its assessment any remaining fire risks associated with serving the small customer loads from either the covered conductor line or within the Remote Grid, i.e., only the long overhead distribution feeder line was considered in this assessment. While Remote Grids are not a general alternative to covered conductor, as the assessment below indicates, they can be effective at reducing wildfire risk for a particular long overhead distribution feeder line that serves small customer loads.

Comparison:

The utilities conducted workshops over multiple days to discuss each sub-driver (from Table 7.1 of the WMP Guidelines) and assessed whether the alternatives have lower, similar or higher effectiveness than a covered conductor system. The results are shown in TABLE PG&E Remedy-21-09-13 below. A red arrow represents a lower effectiveness, an orange arrow represents similar effectiveness, and a green arrow represents a higher effectiveness.

TABLE PG&E-REMEDY-21-09-13:
MITIGATION EFFECTIVENESS COMPARISON OF ALTERNATIVES TO COVERED CONDUCTOR

Risk Event Driver	Sub-driver	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened New Bare Conductor System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Contact-from-Object	Veg. contact	↓	↓	↓	↑	↑	↑	↑
	Animal contact	↓	↓	↓	↔	↔	↑	↑
	Balloon contact	↓	↓	↓	↔	↔	↑	↑
	Vehicle contact	↓	↓	↑	↑	↑	↑	↑
	Other contact from object	↓	↓	↓	↑	↑	↑	↑
Equipment / Facility Failure (EFF)	Connector damage or failure	↓	↔	↔	↔	↔	↑	↑
	Splice damage or failure	↓	↔	↔	↔	↔	↑	↑
	Crossarm damage or failure	↓	↔	↔	↑	↑	↑	↑
	Insulator damage or failure	↓	↔	↓	↔	↑	↑	↑
	Lightning arrestor damage or failure	↔	↔	↔	↔	↔	↑	↑
	Tap damage or failure	↓	↔	↔	↔	↔	↑	↑
	Tie wire damage or failure	↓	↔	↔	↑	↑	↑	↑
	Capacitor bank damage or failure	↔	↔	↔	↔	↔	↑	↑
	Conductor damage or failure	↓	↓	↓	↑	↑	↑	↑
	Fuse damage or failure	↓	↓	↓	↔	↔	↑	↑
	Switch damage or failure	↓	↓	↓	↔	↔	↑	↑
	Pole damage or failure	↓	↔	↑	↑	↑	↑	↑
	Voltage regulator / booster damage or failure	↔	↔	↔	↔	↔	↑	↑
	Recloser damage or failure	↓	↓	↓	↔	↔	↑	↑
	Anchor / guy damage or failure	↓	↓	↓	↔	↔	↑	↑
	Sectionalizer damage or failure	↓	↓	↓	↔	↔	↑	↑
	Connection device damage or failure	↓	↔	↔	↔	↔	↑	↑
	Transformer damage or failure	↔	↔	↔	↔	↔	↔	↔
	Other	↓	↓	↓	↔	↔	↑	↑
Wire-to-wire contact	Wire-to-wire contact / contamination	↓	↓	↓	↔	↑	↑	↑
Contamination	Contamination	↓	↓	↓	↔	↑	↑	↑
Utility work / Operation	Utility work / Operation	↓	↔	↔	↔	↔	↔	↔
Vandalism / Theft - Distribution	Vandalism / Theft	↓	↓	↓	↔	↔	↔	↔
Other- Distribution	All Other - Distribution	↓	↓	↓	↔	↔	↑	↑
Unknown- Distribution	Unknown - Distribution	↓	↓	↓	↔	↔	↑	↑

The analysis shows that covered conductor has greater effectiveness than existing, new, and fire hardened overhead bare conductor systems. In some instances, a fire hardened overhead bare conductor system could provide slightly higher mitigation effectiveness. For example, for car-hit pole (vehicle contact) or other pole damage causes, a hardened overhead bare conductor system was assumed to have much stronger poles preventing occurrences of pole damage and/or wire down from a car-hit-pole scenario. In general, a spacer cable system and an ABC system provide higher effectiveness than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest effectiveness, noting that the analysis of the Remote Grid System scenario was based only upon eliminating a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long overhead distribution feeder line.

Next Steps:

In 2022, the utilities plan to expand this assessment of alternatives to mitigate wildfire risk by including other technologies and mitigations such as replacing fuses, installing Remote-Controlled Automatic Reclosers/Remote-Controlled Switches (RAR/RCS), as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, OPD, EFD, and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of effectiveness for the alternatives.

Potential to Reduce the Need for PSPS:

As part of this sub-workstream, the utilities have documented their general approach to PSPS and conducted a comparison analysis, similar to the Alternatives analysis above, by conducting workshops with SMEs from the six utilities to assess alternatives compared with covered conductor in their ability to reduce PSPS impacts. The utilities used the same alternatives as described in the section above to conduct this assessment. Below, the utilities describe their PSPS approach. Collectively, the utilities summarize the ability of a covered conductor system to reduce PSPS impacts, provide an assessment of alternatives ability to reduce PSPS impacts compared to covered conductor, and describe additional analyses the utilities plan to perform in 2022 to further the utilities' understanding of the ability of covered conductor compared to alternatives to reduce PSPS impacts.

Utilities' PSPS Approach:

Below, the utilities describe their Company's approach to activating a PSPS event and whether they consider raising thresholds when circuits are covered.

<u>SCE</u>:

SCE activates PSPS largely based on two factors. The first factor used to drive PSPS decisions is the FPI, which estimates the likelihood of a spark turning into a major wildfire. FPI is calculated using forecasted wind speed, dewpoint depression, and various fuel moisture variables which are generated from SCE's customized version of the Weather Research and Forecasting (WRF) model. SCE's FPI scores range from 1 to 17, and any score at or above 12/13 (based on, for example, fire climate zone) is considered high risk. SCE reviews fire potential related products from the National

Weather Service (NWS) and the GACC to confirm the wildfire threat related to PSPS. The second factor used to drive PSPS decisions is wind speed. SCE considers the NWS Wind Advisory levels (defined as 31 mph sustained wind speed and 46 mph gust wind speed) and the 99th percentile of historical wind speeds in the area to set activation thresholds. The Wind Advisory level is chosen because of the propensity for debris or vegetation to become airborne, while a circuit's 99th percentile wind speeds represent rare or extreme wind speeds that a particular circuit sees around four times per year. In 2021, SCE raised its de-energization thresholds for isolatable segments or circuits that have had covered conductor installed. The de-energization threshold for isolatable segments with covered conductor is 40 mph sustained and 58 mph gusts, which aligns with the NWS high wind warning level for windspeeds at which infrastructure damage may occur.[15]

Once SCE's meteorologists confirm weather forecasts show an upcoming breach of FPI and circuit-specific wind speed thresholds, SCE activates its PSPS IMT and begins preparations for the upcoming event. Whether remotely due to the COVID-19 pandemic, or in-person at SCE's Emergency Operation Center, the IMT begins notifying affected parties. Notifications are sent to first responders, public safety partners, local governments, tribal governments and critical infrastructure providers approximately 72 hours prior to de-energization, followed by notifications to all other customers in scope approximately 48 hours prior to de-energization. SCE continues to provide additional notifications as well as notifications of imminent de-energization as information becomes available during the PSPS events (discussed in Section 8.2.4), develop event and circuit-specific de-energization triggers (inputs to which are discussed in Section 8.2.2) and direct resources to perform pre-patrols of all circuits in scope. Decision-making factors and protocols for PSPS de-energization are discussed in SCE's WMP Section 8.2.2.

PG&E:

PG&E does not make specific changes in its PSPS protocols due to new improvements and mitigation initiatives, including grid hardening. The underlying models are based on historical data and not on estimating the effect of changes to system operations before they have occurred, which PG&E believes would be less accurate. However, since PG&E's PSPS models are based on historical data, new improvements and mitigation initiatives will be included in the models once the current changes are reflected in the historical data which the model incorporates over time. For example, when PG&E improves the quality of some specific assets, it expects a reduction in the chance of that asset causing an ignition. However, PG&E does not manually input a reduction in the ignition probability in the model. Over time, the historical observed data is expected to change, and this data will feed into PG&E's models and gradually change its models' parameters.

PG&E's thresholds for PSPS are based on a risk assessment that combines the probability of utility related outages and ignitions, called the Ignition Probability Weather

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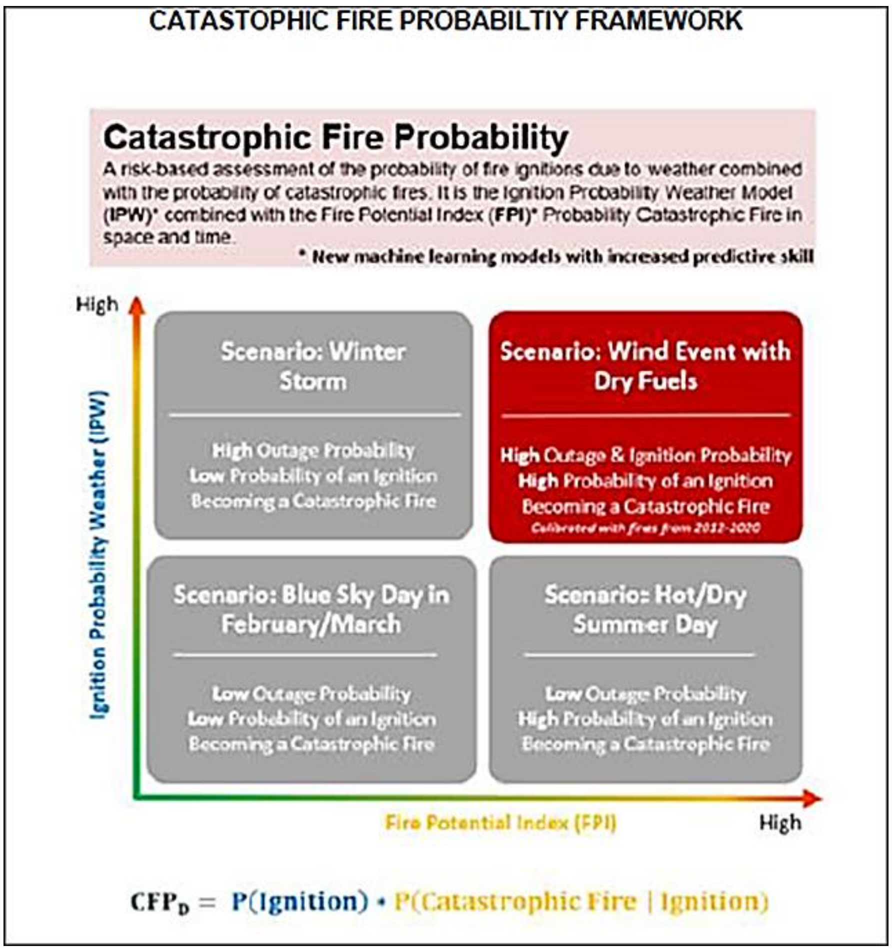
15 If actual conditions suggest more risk, or in large-scale events when many circuits are under consideration for shutoff, the de-energization thresholds may be lowered (discounted), meaning power on a circuit will be turned off at lower wind speeds.

(IPW) model, and the probability of catastrophic fires, called the Fire Potential Index (FPI). This combination is called the Catastrophic Fire Probability (CFPD) and is given by the equation:

$$CFPD = p\ ignition * p\ catastrophic\ fire\ ignition = IPW * FPI$$

The IPW is a function of grid-performance given the weather conditions and is built using historical hourly weather data, outages, and ignitions in a machine learning model framework for localized areas. The guidance values PG&E utilizes when making a PSPS decision through the lens of this framework is a CFPD (IPW*FPI) value > 9. This value was determined by running 70 PSPS sensitivity studies from 2008 through 2020. Through this 13 year "lookback" analysis, PG&E evaluated the customer impacts through multiple dimensions (size, duration, frequency, repeat events, etc.), the days PSPS events would have occurred, as well as whether historic fires caused by utility infrastructure would have been de-energized using this analysis. The conceptual CFPD framework is presented in Figure PG&E-REMEDY-21-09-14 below.

FIGURE PG&E-REMEDY-21-09-14:
PG&E CONCEPTUAL CATASTROPHIC FIRE PROBABILITY FRAMEWORK



PG&E data scientists and meteorologists have taken steps to quantify the probability of outages, ignitions and catastrophic fires using both logistic regression and machine learning models. PG&E does not use wind speed thresholds on a per-circuit basis as a gauge of outage or ignition probability and therefore do not increase or decrease its wind speed thresholds where hardening has been performed. In PG&E's framework, the effects of grid-hardening and covered conductor would be handled in the IPW, which predicts the probability of utility-caused ignitions.

Overhead system hardening is expected to reduce the probability of outages and ignitions. PG&E believes that adjustments to PSPS thresholds should be considered carefully and based on robust performance data of survivability in the field during actual weather events. Covered conductor, for example, does not drive the fire ignition risk to zero. Trees can still fall into overhead lines and break covered conductor and cause an ignition. Based on aerial LiDAR, there are several million trees that have the potential to strike assets in PG&E's HFRA, which is an ignition pathway that has caused several catastrophic fires recently.

PG&E has built a PSPS model framework that can account for changes overtime based on actual performance data. The machine learning IPW framework (probability of ignitions) is flexible as PG&E does not have to consider each individual program such as covered conductor and EVM to adjust wind or PSPS thresholds on each circuit or circuit segment. Rather, the model framework addresses positive and negative changes in grid performance and reliability year-over-year as PG&E applies a time-weighted approach to weight more recent years of learned performance more heavily in the final model output. The model accounts for the performance of local grid areas hour-by-hour based on the wind speed observed at that hour and if outages or ignitions occur or not. The IPW model is 13 models trained on each year separately from 2008-2020 using hourly data and hourly outages. PG&E applies an exponential time-weighted approach to capture more rapid changes in local areas to be captured in the model (both negative - increased tree mortality, asset degradation, drought etc.; and positive – conductor and pole replacement, EVM, etc.). PG&E is in the process of updating the model with 2021 outage, ignition and historical weather data. When the model is updated, performance in 2021 will have the most model influence while 2008 will have the lowest.

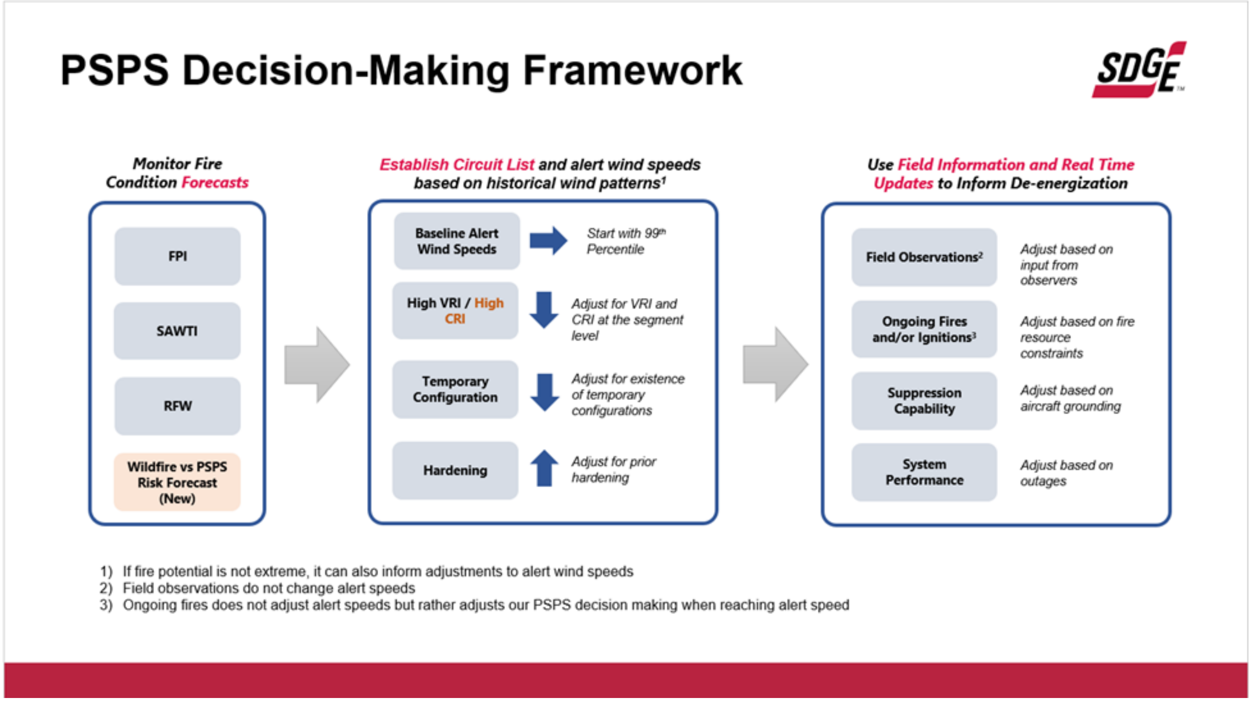
Since the IPW model accounts for changes over time and it evaluates PSPS through the risk-based assessment above, PG&E does not propose at this time adjusting its CFPD thresholds for circuits where grid-hardening has been performed. Instead, any positive effects from grid hardening, EVM, inspections, and other improvements will be trained in the Machine Learning IPW through this learned performance approach. Positive changes from any program or exogenous factors will lower the probability of outages and ignitions in these areas accordingly. In addition, if PG&E adjusts CFPD values to some circuits, it could make the fatal mistake of double counting the performance benefit achieved as changes in performance are inherently accounted for in the IPW model. PG&E welcomes feedback on its risk-based approach and ideas on how it can improve.   One of the ideas PG&E is contemplating for future development of models is utilizing areas that have been hardened as a local feature of the IPW model.

<u>SDG&E</u>:

SDG&E utilizes multiple factors to assist in the decision to de-energize. See FIGURE PG&E-REMEDY-21-09-15, below, that illustrates this PSPS decision-making framework. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a Circuit Risk Index (CRI) to identify locations in the system with a potential of having higher failure rates. Due to the dynamic nature of wildfire conditions SDG&E uses a real–time situational awareness technique to determine when to use PSPS, considering a variety of factors such as:

- Weather Condition - FPI
- Weather Condition - Red Flag Warnings
- Weather Condition - SAWTI
- Weather condition - 72-hour circuit forecast
- Vegetation conditions and Vegetation Risk Index (VRI)
- Probability of Ignition/Probability of Failure
- Field observations and flying/falling debris
- Information from first responders
- Meteorology, including 10 years of history, 99th and 95th percentile winds
- Expected duration of conditions
- Location of any existing fires
- Wildfire activity in other parts of the state affecting resource availability
- Information on temporary construction

FIGURE PG&E-REMEDY-21-09-15:
SDG&E PSPS DECISION-MAKING FRAMEWORK



To-date, SDG&E has installed approximately 18 miles of covered conductor with an average age of less than one year. Therefore, SDG&E has not yet accumulated sufficient data to determine exactly how PSPS criteria will differ on circuit-segments that consist entirely of covered conductor versus bare conductor, though SDG&E does anticipate higher wind speed tolerances in these areas. In addition to real-world experience, and operations and benchmarking with other utilities, SDG&E will have a third-party evaluate the likelihood and effect specific to covered conductors clashing at various wind speeds to understand and help quantify any potential increases to wind speed tolerances on covered conductor segments.

<u>PacifiCorp</u>:

PacifiCorp has historically leveraged multiple factors when deciding to implement a PSPS. Throughout 2021, PacifiCorp's newly established meteorology department worked to develop the capability to support real time risk assessments and forecasting and inform decision making protocols during periods of elevated risk such as PSPS assessment and activation. Situational awareness reports are generated daily which identify where fuels (dead and live vegetation) are critically dry, where and when critical fire weather conditions are expected (gusty winds and low humidity), and where and when the weather is forecast to negatively impact system performance and reliability. It is the intersection of these three factors that highlights an elevated risk to be considered for a potential PSPS event. These factors are then layered alongside real time local conditions such as real time weather measurements and field observer reports, as well as dynamic input from Public Safety Partners to characterize the local impact of a PSPS. All of these factors combined are used to determine whether to implement a PSPS.

During 2021 the following forecasted factors were considered in the decision to implement a watch:

- Comparison of forecasted wind gusts to localized history trends
- GACC-7 Day Fire Potential Outlook (High Risk with a Wind Trigger)
- Presence of any advisories such as the Fuels and Fire Behavior Advisory in effect for Northern California
- Local drought conditions
- Vapor Pressure Deficit
- Keetch-Byram Drought Index
- Presence of any Red Flag Warnings

In addition, the following real time observations were additionally included in the decision to de-energize:

- Actual wind gusts in the area
- Field observer reports
- Observer input regarding any observed precipitation (or other meteorological input)
- Measured wind speeds at utility owned weather stations
- Approximate relative humidity forecasted vs actual
- Local public safety partner input

While PacifiCorp continues to refine its methodology for determining inputs critical to making PSPS decision, however, at least for 2022, PacifiCorp does not anticipate at this time that covered conductor coverage will modify its PSPS decision-making process because PacifiCorp does not have full covered conductor coverage on any circuit or controllable sub-circuit. However, as the Company increases covered conductor coverage, it will continue to assess its effectiveness, and expect it to impact its decision-making once the necessary coverage and operational history is obtained.

<u>Liberty</u>:

In evaluating when a PSPS event should be initiated, Liberty monitors local weather conditions with its weather stations throughout its service territory and collaborates with Reax Engineering, a fire and weather scientific consultant, the NWS in Reno, Nevada, and local fire officials. The initiation of PSPS events are influenced by the following factors:

a. <u>Red Flag Warnings</u> – Issued by the NWS to alert of the onset, or possible onset, of critical weather or dry conditions that would lead to increases in utility-associated ignition probability and rapid rates of fire spread.

b. <u>Low humidity levels</u> – Potential fuels are more likely to ignite when relative humidity is low and vapor pressure deficit is high.

c. <u>Forecast sustained winds and gusts</u> – Fires burning under high winds can increase ember production rates and spotting distances. Winds also can transfer embers from lower fire risk areas into high risk areas, igniting spot fires and increasing wildfire potential.

e. <u>Dry fuel conditions</u> – Trees and other vegetation act as fuel for wildfires. Fuels with low moisture levels easily ignite and can spread rapidly.

e. Observed Energy Release Component (ERC)

f. Observed wind gusts

g. Observed Fosberg Fire Weather Index (FFWI)

h. Observed Burning Index (BI)

Liberty employs two de-energization decision trees, one for the Topaz and Muller 1296 r3 PSPS zones, and another for all other zones. In each case, the ERC, observed wind gust, and FFWI criteria are evaluated simultaneously to test whether any exceed the defined threshold. The figures below represent the de-energization decision trees:

FIGURE PG&E-REMEDY-21-09-16:
LIBERTY DE ENERGIZATION DECISION TREE (TOPAZ AND MULLER 1296 R3 ZONES)

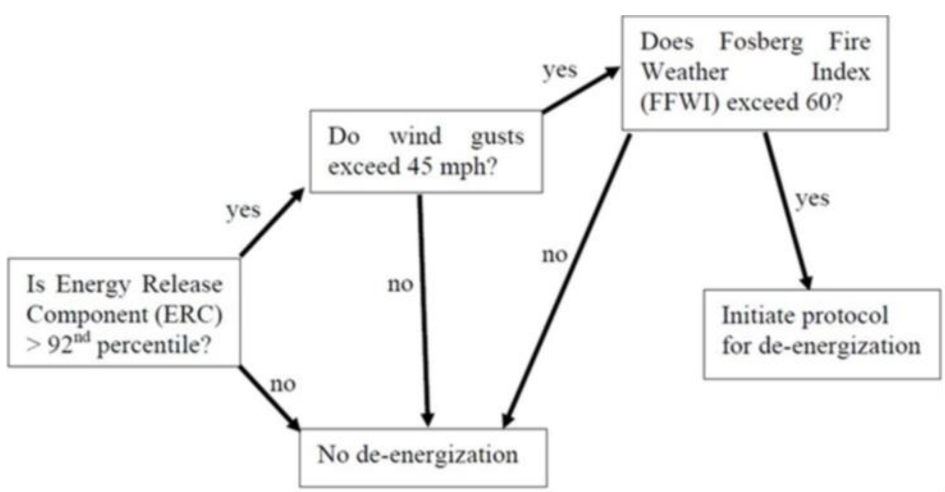
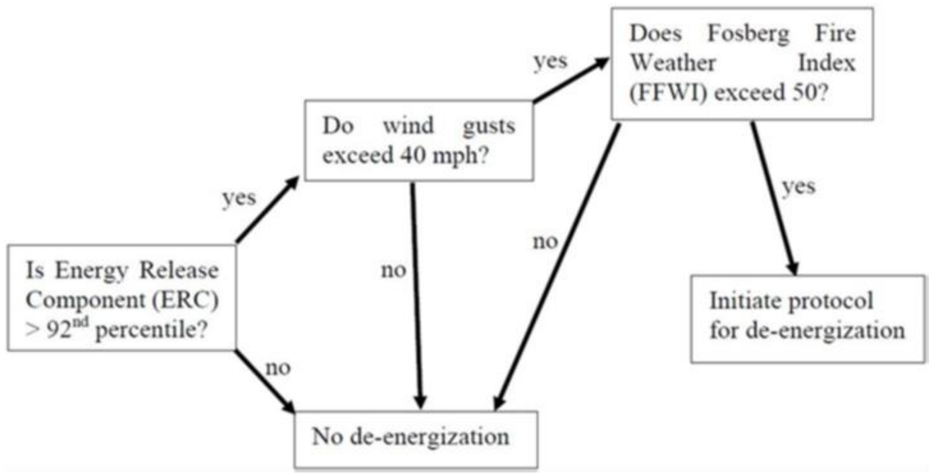


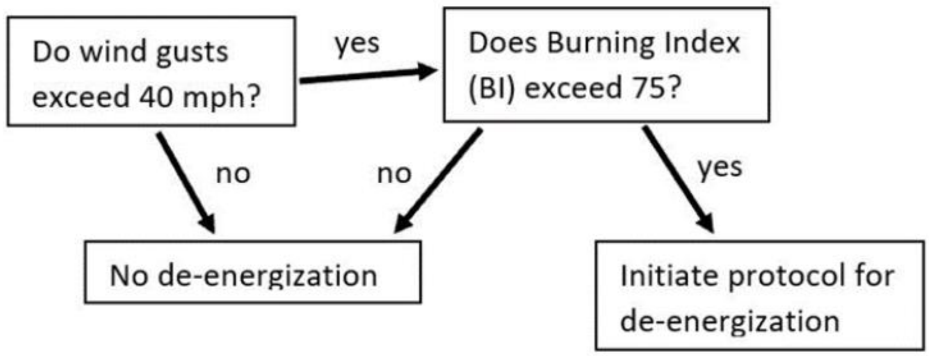
FIGURE PG&E-REMEDY-21-09-17:
LIBERTY DE ENERGIZATION DECISION TREE (ALL OTHER ZONES)



In January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index (BI). BI adds an increased layer of information regarding fire potential to its already robust predictive formula. It accounts for predominant fuel type, live and dead fuel moisture, and short-term fluctuations in fire weather conditions. Use of this new formula with increased information from newly installed additional weather stations enables further granularity in the area of alternative responses to initiating a PSPS, such as managing recloser technology, de-energizing specific circuits and /or increasing patrols in specific geographic areas of concern. Liberty now utilizes both the current predictive formula and the enhanced model in order to assess improved data.

The figure below shows the current BI/gust de-energization formulation that is being evaluated by back testing against historical weather station observations and archived weather forecast data. The purpose of this formulation is to try to better capture "black swan" events, where extremely high winds may still have the ability to cause dangerous fire conditions even though temperatures are low and humidity levels are not critical, which can happen in the spring or fall more than the middle of the typical fire season.

FIGURE PG&E-REMEDY-21-09-18:
LIBERTY'S CURRENT BURNING INDEX/GUST DE ENERGIZATION FORMULATION



<u>BVES</u>:

BVES evaluates many factors when initiating a PSPS event. However, in general, BVES will initiate a PSPS event when the NFDS fire danger forecast is high Risk (Brown, Orange or Red), and the actual sustained wind or 3-second wind gusts exceed 55 mph. In addition, BVES may initiate a PSPS if in the Utility Manager's judgement, actual conditions in the field pose a significant safety risk to the public. Individual circuits are evaluated for PSPS and may be individually de-energized to limit the area impacted by a PSPS.

Once complete overhead circuits are hardened and covered conductor is installed, BVES will consider raising the wind speed threshold for PSPS. The revised wind speed threshold for overhead structures with covered conductors is currently under evaluation. To date, BVES has never been required to activate a PSPS event.

Covered Conductor Potential to Reduce PSPS Risk:

As described in the sections above, utilities generally believe that a fully-isolatable circuit-segment or zone of protection that has covered conductor can reduce PSPS impacts beyond an overhead bare conductor system. SCE, for example, increases its de-energization threshold for isolatable circuit-segments with covered conductor from 31 mph (sustained wind gusts) and 46 mph (gust) to 40 mph (sustained) and 58 mph (gust), which aligns with the NWS high-wind warning level for windspeeds at which infrastructure damage may occur. However, the rule of thumb starting point is not always 31 mph and 46 mph and instead is based on NWS high wind warning (potential asset damage). Furthermore, through back-casting analysis of 2021 PSPS events, SCE estimates that its efforts in grid hardening (largely due to covered conductor), situational awareness, and improved risk modeling (which allowed for adjustments to PSPS thresholds) helped reduce Customer Minutes of Interruption (CMI) by 43%, the number of customers de-energized by 42%, and the number of circuits de-energized by 29% from what they otherwise would have been under the same weather conditions. These data demonstrate that covered conductor provides PSPS benefits compared to overhead bare conductor systems. As the other utilities gain experience in installing more covered conductor, they plan to continue to assess raising their de-energization criteria for isolatable circuit-segments or zones of protection that are fully covered.

Alternative Comparison:

The utilities conducted workshops over multiple days to discuss and assess whether the alternatives have lower, similar or higher benefits than a covered conductor system in reducing PSPS impacts. The utilities considered three PSPS benefits: (1) reduce PSPS frequency (# of de-energizations), reduce PSPS duration (CMI), and reduce number of customers impacts by PSPS (i.e., customers in scope). The results are shown in Table PG&E Remedy-21-09-14 below. A red arrow represents a lower benefit, an orange arrow represents similar benefits, and a green arrow represents a higher benefit.

TABLE PG&E-REMEDY-21-09-14:
S IMPACT BENEFITS COMPARISON OF ALTERNATIVES TO COVERED CONDUCTOR

PSPS Event Impact	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Reduce PSPS Frequency (# of de-energizations)	↓	↓	↔	↑	↑	↑	↑
Reduce PSPS Duration (CMI)	↓	↓	↔	↑	↑	↑	↑
Reduce Number of Customers Impacted by PSPS (customers in scope)	↓	↓	↔	↑	↑	↑	↑

The analysis shows that covered conductor has greater PSPS benefits than existing and new overhead bare conductor systems. SDG&E's upgraded and fire hardened system has shown benefits in reducing PSPS frequency, duration, and number of customers impacted. The utilities did not quantify these benefits to determine how much different are the benefits of a fire hardened bare overhead system compared to a covered conductor system and thus identified for this initial assessment a similar benefit. Similar to the assessment in the section above, a spacer cable system and an ABC system provide could provide higher benefits than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest-level of benefits. Please note that the Remote Grid System scenario was based only on a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long feeder line.

Next Steps:

In 2022, the utilities plan to expand this assessment of covered conductor and alternatives in their ability to reduce PSPS impacts by including other alternative technologies and mitigations such as replacing fuses, installing RAR/RCS as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, D-OPD, EFD and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of the benefits for the alternatives.

Costs:

The utilities have prepared an initial capital cost per circuit mile comparison of the installation of covered conductor. To construct this unit cost comparison, the utilities organized their capital costs (and/or estimates) into six cost categories. These categories include labor, material, contract, overhead, other, and financing. Labor represents internal utility resources, such as field crews, that charge directly to a project work order. Materials include conductor, poles, etc. that get installed as part of a project. Contract represents all contractors, such as field crews and planners, and consultants utilities use as part of their covered conductor programs. Overhead represents costs, such as engineers, project managers and administrative and general, that get allocated to project work orders. Other represents costs such as land fees, permit fees and costs not assignable to the other categories. Financing represents allowance for funds used during construction (AFUDC) which is the estimated cost of debt and equity funds that finance utility plant construction and is accrued as a carrying charge to work orders. These cost categories are intended to capture the total capital cost per circuit mile of covered conductor installations. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2021. TABLE PG&E Remedy-21-09-15, below, shows the initial covered conductor capital unit cost per circuit mile comparison across the six utilities.

TABLE PG&E-REMEDY-21-09-15:
COMPARISON OF COVERED CONDUCTOR CAPITAL COSTS PER CIRCUIT MILE

	SCE		PG&E		SDG&E		Liberty		PacifiCorp		Bear Valley	
Cost Components	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%
Labor (Internal)	$ 8,000	1%	$ 209,000	19%	$ 182,000	13%	$ 56,000	4%	$ 2,000	0%		
Materials	$ 115,000	20%	$ 161,000	15%	$ 130,000	9%	$ 132,000	8%	$ 204,000	34%	$234,000	23%
Contractor	$ 335,000	59%	$ 470,000	43%	$ 481,000	34%	$1,167,000	75%	$ 272,000	45%	$733,000	71%
Overhead (division, corporate, etc.)	$ 96,000	17%	$ 226,000	21%	$ 418,000	29%	$ 188,000	12%	$ 62,000	10%	$38,000	4%
Other	$ 5,000	1%	$ 6,000	1%	$ 173,000	12%	$ -	0%	$ 60,000	10%	$26,000	3%
Financing Costs	$ 6,000	1%	$ 11,000	1%	$ 43,000	3%	$ 9,000	1%	$ 6,000	1%		
Total	$ 565,000	100%	$ 1,083,000	100%	$ 1,427,000	100%	$1,553,000	100%	$ 606,000	100%	$1,031,000	100%

As illustrated in Table PG&E Remedy-21-09-15, the capital cost per circuit mile ranges from approximately $565,000 to approximately $1.5 million. The capital cost per circuit mile for covered conductor varies due to multiple factors such as type of covered conductor system and components installed, terrain, access limitations, permitting, environmental requirements and restrictions, construction method (e.g., helicopter use), amount of poles/equipment replaced, degree of site clearance and vegetation management needed, and economies of scale. Below, the utilities generally describe the make-up of their covered conductor capital costs and the factors that contribute to the cost differences.

Covered Conductor Capital Costs:

<u>SCE</u>:

<u>CC Unit Cost Make Up</u>:

The costs in SCE's WCCP incur through the main cost categories of labor, materials, contracts, overhead, and other and are captured in SAP work orders. SCE's unit costs have historically been presented as direct costs only (exclude corporate overheads and financing costs), and is the average cost of nine different regions within SCE's service area. For purposes of this report, SCE has added corporate overheads (to the overhead cost category) and financing costs to its direct unit cost for comparison with the other utilities.

SCE has two covered conductor designs that vary depending on system voltage requirements. These include 17 kV and 35 kV covered conductor designs, the former of which SCE utilizes on its 12 kV and 16 kV distribution systems, and the latter of which SCE utilizes on its 33 kV distribution systems. The primary difference between these two designs is the thickness of the inner and outer layers. For example, 35 kV covered conductor design has a thicker covering, allowing it to withstand intermittent contact at higher voltages. Additionally, SCE uses four ACSR conductor sizes (i.e., 1/0 AWG , 336.4 (18x1) AWG, 336.4 (30/7) AWG, 653.9 AWG) and three copper conductor sizes (i.e., #2 AWG, 2/0 AWG, 4/0 AWG). Circuit and customer loading requirements will determine the conductor size. SCE may also use higher strength conductors to resolve ground clearance issues in areas subject to ice. The vast majority (99%) of SCE's covered conductor installations have been with the 17 kV covered conductor design which is lower cost than the 35 kV covered conductor design.

SCE installs covered conductor in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. SCE's WCCP also includes the installation of FRPs, composite crossarms, wildlife covers, polymer insulators, and vibration dampers. SCE uses FRPs, which are more expensive than wood poles, when pole replacements are required to meet pole-loading criteria. SCE replaces, on average, between 10 to 12 poles per circuit mile. Composite crossarms are also used to replace traditional wood crossarms as part of the WCCP. Like composite poles, composite crossarms are also higher cost than wood crossarms. SCE also employs wildlife covers and installs them on dead-ends, terminations, equipment jumper wires, connectors, and equipment bushings. In areas below 3,000 feet in elevation or high-tension installations, SCE requires the use of vibration dampers to mitigate conductor damage due to Aeolian vibration.

SCE primarily uses contractors to construct its covered conductor projects and a mix of contract and SCE labor to design its covered conductor projects. SCE field labor and contract field labor costs are charged directly to the project work orders. SCE design resources charge a division overhead account that gets allocated to work orders because SCE planners work on multiple types of projects. Costs for design scope performed by contractors is charged directly to the covered conductor work order (contract category) because this contracted work is specific to covered conductor projects. Materials such as conductor, poles, and crossarms are charged directly to the project work order. The Overhead category includes operational resources and items centrally managed and include costs such as equipment (e.g., vehicles, tools and supplies for field work) and managerial resources that are allocated to work orders. As noted above, the Overhead category also includes corporate overheads, which includes costs for administrative and general, pension and benefits, payroll taxes, injuries and damages, and property taxes.

Cost Drivers:

SCE's covered conductor projects have an estimated timeframe of 16 –24+ months from initial scoping to project completion. There are many factors that may impact the total project lifecycle and costs, including permitting and environmental requirements, easements, geography and terrain, construction resource availability, and other construction-related factors. The largest driver of the cost is typically the contract cost for which contractor rates and construction time vary across locations in SCE's HFRA. For example, regions with more difficult terrain and mountainous areas typically have higher contractor rates. Projects in these areas also typically take longer to construct and require more costly construction methods (e.g., helicopter use). Beyond challenging terrain, projects can take more time due to other factors such as permitting, weather (e.g., rain/snow conditions, Red Flag Warning (RFW) days, etc.), and environmental restrictions (e.g., nesting birds that don't allow crews to work in certain areas until the birds have fledged). There are also many other drivers that can increase costs such as local agency restrictions (e.g., only night work allowed), direct environmental costs (e.g., if biological monitors are required), vegetation (i.e., requires vegetation clearing), access constraints (i.e., requires helicopter construction and/or access road rehabilitation), customer impact (i.e., temporary generation required for a circuit), and operating restrictions (e.g., crews are pulled off work). Many of these factors can also limit flexibility and reduce productivity causing construction costs to increase. The cost per circuit mile in some regions, such as SCE's Rurals Region, is more expensive than other regions. In some instances, this cost difference can be $300,000 or more per circuit mile.

As seen in TABLE PG&E Remedy-21-09-15 above, SCE's unit cost is the lowest of the six utilities. While SCE has described many factors that affect its covered conductor costs, some of the reasons why SCE's costs may be lower than the other utilities include economies of scale with SCE installing over 1,000 circuit miles per year and its ability to bundle work for its contractors. Bundling work enables multiple projects to be completed in the same general area which minimizes mobilization and demobilization costs and increases contractor productivity. SCE has also not generally observed a steady nor large amount of vegetation management or access road rehabilitation costs across its installations. With thousands of circuit miles installed, these types of incurred costs are low when averaged across SCE's portfolio of completed installations. As noted above, SCE also only replaces, on average, 10 to 12 poles[16] per circuit mile and its WCCP is focused on covered conductor and does not include other major equipment upgrades.

PG&E:

CC Unit Cost Make Up:

PG&E's data set represents System Hardening projects scoped by Asset Management and approved by its Wildfire Steering Governance Committee. The covered conductor projects go through the following major phases to completion:

- Estimating and Design
- Dependency (Permitting, Land Rights and Environmental Review)
- Construction Resourcing and Contracting
- Construction
- Document and Close Out

A subset of these projects is "Fire Rebuild" projects. These set of System Hardening projects arise from hardening scope after a fire or other emergency events in Tier 2/3. Due to the emergency nature to rebuild assets quickly to serve the community, all the steps described above in base System Hardening are accelerated.

PG&E's unit cost analysis is based on fully completed projects with costs-since-inception (including costs from previous years) recorded in its system of record (SAP). Based on that criteria, the data set captures 111 miles worth of projects that were completed in 2021. Construction transpired in 11 different divisions with varying terrains and conditions. 14 miles were Fire Rebuild, which typically have a lower unit cost, the remaining 96 were Base (regular) System Hardening.

Costs were organized per the six main categories agreed upon with the other utilities. The summary table blends both contract and internally resourced projects. 44 miles were constructed using external crews, categorized as Contract and 66 miles were constructed using Internal labor, categorized as Labor.

PG&E's Overhead Hardening (covered conductor installation) scope achieves risk reduction through these foundational elements: bare primary and secondary conductor replacement with covered equivalent, pole replacements, non-exempt equipment replacement, overhead distribution line transformer replacement with transformers that

16 SCE's average number of poles per circuit mile is approximately 29. As such, 10-12 poles represents approximately 34% to 41% of the average number of poles per circuit mile.

have FR3 fluid, framing (composite crossarms and insulators) and animal protection, and vegetation clearing.

Cost Drivers:

PG&E's covered conductor installation costs are driven by these key contributors:

- Pole replacement – nearly 100% of the poles require replacement due to the additional weight/sag of the new covered conductor.
- PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition component replacement impacts the cost by including the material and labor installation cost of the new equipment where it requires replacement.
- Vegetation clearing in support of the new overhead line can be a significant cost added to these projects. Both the increased height of the poles, the widened cross-arms, and the increased sag of the line can vary the cost considerably. This cost alone can add between $50,000 to $400,000 per mile depending on the terrain and the location of the line. The rural nature of much of the high-risk HFTD infrastructure drives this need.

SDG&E:

CC Unit Cost Make Up:

Each project goes through a six-stage gate process as follows:

- Stage 1 – Project Initiation (duration ~1-3 months)
- Stage 2 – Preliminary Engineering & Design (duration ~6-9 months)
- Stage 3 – Final Design (duration ~3-5 months)
- Stage 4 – Pre-Construction (duration ~1-2 months)
- Stage 5 – Construction (duration ~3-4 months)
- Stage 6 – Close Out (duration 8~-10 months)

The total duration of a project has an estimated duration of approximately 22 to 33 months.

SDG&E's covered conductor per mile unit capital costs is made up of the following six major cost categories:

1. Labor (internal) – Directs costs associated with SDG&E full-time employees (FTE), including but not limited to individuals from project management, engineering, permitting, environmental, land management, and construction departments. This cost assumes approximately 25% of the electric work is completed by internal SDG&E construction crews.

2. Materials – Estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.

3. Contractor – Estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. This cost assumes approximately 75% of the electric work is completed by contract crews.

4. Overheads – Estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by Qualified Electrical Worker (QEW), staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.

5. Other – Estimated costs associated with indirect capital costs. These costs are estimated to be approximately 14.3% of direct capital costs that accumulate on a construction work order. This includes administrative pool accounts that are not directly charged to a specific project, including internal labor vacation, sick, legal, and other expenses.

6. Financing Costs – Estimated costs associated with the collection of AFUDC when a construction work order remains active. Most SDG&E jobs are active for approximately 6 to 10 months from the time the job is issued to construction until it is fully completed and the collection of AFUDC charges stop.

Cost Drivers:

Costs can vary significantly from project to project for a variety of reasons, including engineering and design, land rights, environmental, permitting, materials, and construction. Below is a description of these factors and why the costs can vary from project-to-project.

Engineering & Design: SDG&E collects LiDAR (Light Imaging Data and Ranging) survey data before the start of design and again after construction is completed. During the LiDAR data capture, other data including photos (i.e., ortho-rectified images of the poles and surrounding area, and oblique pole photos), and weather data is acquired. After collection of the raw LiDAR and Imagery data, it is processed to SDG&E's specification and includes feature coding and thinning of the LiDAR data, and selection and processing of the imagery data. The entire process for delivery to SDG&E's specification can take weeks to months depending on the size of the data capture. This LiDAR data capture is used to support the base-mapping, engineering, and design processes (Stage 1 and Stage 6).

Currently, the engineering and design of all covered conductor projects are conducted by engineering and design consultants, and their deliverables are reviewed by a separate Owner's Engineering (OE) consultant to ensure compliance with SDG&E standards and guidelines. At this time, SDG&E does not have the resources to conduct the engineering and design required at this scale of work; however, there is an assigned SDG&E full time engineering staff that provide oversight of all engineering and design consultants, including the OE. The engineering component of work relates to the structural analysis, including Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) modeling, foundation calculations, or geotechnical studies. The design component includes the drafting, entering design units into SAP for material ordering and costing, and building the job packages that are sent to construction. In some cases, one consultant can perform both the engineering and design function, and in others cases an engineering consultant collaborates with a design consultant. In all cases, SDG&E's Owner's Engineer will perform both engineering and design review support. Costs from consultants can vary depending on the size and complexity of the project, and due to various other factors including environmental constraints, land constraints, permitting requirements, or scoping changes that can occur from the start of design and throughout construction. The design stage (i.e., start of design to issuance of job package to construction) typically takes anywhere from six months to two years depending on the size and complexity of the project and the challenges with acquisition of land rights, environmental release, and permitting.

SDG&E requires every pole be engineered using PLS-CADD software during two stages of the project lifecycle, the design phase and the post-construction phase. This software allows SDG&E to leverage LiDAR survey data (pre- and post-construction) and AutoCAD drawings, and to design the poles, wire, and anchors to meet General Order (GO) 95 Loading (Light and Heavy Loading) and Clearance Requirements, and to meet Known Local Wind requirements (e.g., 85 mph and in some cases 111 mph wind). SDG&E also requires its engineering and design contractors who use the PLS-CADD software to have a California-registered Professional Engineer oversee and stamp the final PLS-CADD design.

<u>Land and Environmental</u> – SDG&E requires all projects to go through a land and environmental review process at each stage of the design process. These processes are predominantly supported with the help of land management and environmental service consultants but are overseen by SDG&E representatives in each respective department. The land process includes research of SDG&E's land rights, interpretation, and may include support obtaining the proper land rights when required. Through the land rights review process, SDG&E determines the land ownership its facilities (e.g., poles, anchors, and wire) are within and get an interpretation of the limits of its land rights. The results are shared with the engineering and design team and environmental. Once the land rights are determined, environmental performs an assessment, determines the environmental impacts if any, and provides input to the design process to minimize and/or avoid environmental impacts. These land and environmental reviews can drive changes to the design and add time and cost to the project. For example, in many cases, SDG&E does not have the land rights to build the overhead covered conductor design within its existing easement, or in some cases it only has prescriptive rights. In those cases, SDG&E must amend or acquire the proper land rights, or redesign the project, if possible, to stay within the land and/or environmental constraints. If acquiring or amending land rights is required, this can take weeks to

months depending on the property owner (e.g., private, BIA, State, Federal, or Municipality) and the level of change to the existing conditions.

<u>Materials</u> – SDG&E's philosophy with covered conductor, like SCE, is to install it in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. Where connections are necessary, piercing connectors are used to avoid stripping the wire and causing damage to the conductor and negating the need to wrap the connection with insulating tape. SDG&E also requires the use of vibration dampers, where necessary, to mitigate conductor damage due to Aeolian vibration. SDG&E replaces most wood poles to steel, and in some cases replaces existing steel poles if they are not adequate to support the new wire (e.g., inadequate clearance and/or mechanical loading capacity). In many cases equipment is replaced during these reconductor projects if it is older, is showing signs of failure, and/or needs to be brought up to current standards. The reason to replace wood poles with steel is due to several reasons, including the fact steel is more resilient to fires than wood and is seen as a defensive measure, steel is a man-made material and the strength and dimensions are consistent and have much smaller tolerances than wood, and because many of SDG&E's wood poles are over 50 years old. In some cases, SDG&E may also need to relocate the pole line to an area where it is more accessible to build and maintain but will require obtaining a new easement. SDG&E also replaces wood crossarms with fiberglass crossarms, insulators with polymer insulators, switches, and regulators. For transformers, SDG&E developed specific criteria for replacement. For example, where a transformer will be replaced if it is internally-fused regardless of age, if it's greater than 7 years old, if it has visual defects or damage (leaks, burns, corrosion, etc.), is less than 25 kVA, or if the transformer does not pass volt-drop-flicker calculation. SDG&E also replaces secondary wire that is either open (non-insulated) or "grey wire" (covered secondary wire where the insulation is grey in color). On most projects, there is a smaller underground job associated with the overhead work. This occurs when a pole feeds underground (e.g., a Cable or Riser Pole) and the new pole location may be too far from the existing position such that the existing cable, conduit, and terminations may not reach the new pole position. In these cases, a small job will be initiated to have the crews intercept the run of underground conduit, install a new handhole, install a new run of conduit and cable to the new pole location, and splice the cable in the new handhole to make the connection to the existing underground system.

In 2021, SDG&E experienced significant material supply chain issues, especially with covered conductor materials due to impacts from COVID-19. In the case of covered conductor, SDG&E currently sources the wire from multiple suppliers; however, the associated materials such as piercing connectors and piercing dead-ends come from one supplier out of Europe and experienced significant delays in getting orders delivered due COVID-19 and issues with US Customs paperwork. SDG&E also experienced delays receiving other material due to COVID-19 supply chain disruptions and competition for the same materials used by other utilities including transformers and other materials common to various utilities across the country. Material delays can cause construction delays or cause construction to work less efficiently, thus impacting project schedules and costs.

<u>Construction</u> – One of the most significant variables, and most difficult to predict, is the civil portion of construction. The civil portion of a project includes the pole hole and

anchor hole digging and can vary significantly depending on several factors including accessibility (truck accessible versus non-truck accessible), soil conditions (rock versus soft soil), methods of digging (hand tools versus machine), and environmental constraints that may limit the method of digging or dictate access protocols. For example, a 0.7 miles project completed a couple of years ago was on the side of a steep mountain side and all the material, equipment (pneumatic drill and hand tools), and crews had to be flown in and out every day for months. The civil crews encountered significant rock at most locations and the spoils from the digging had to be flown out via helicopter due to the restrictions placed on construction due to environmental concerns rather than be spread-out on location. Each pole and anchor were back-filled with concrete using helicopters because of the slope of the mountain and due to the significant mechanical loading due to winter storms. In contrast to this mountain side project example, SDG&E has had other projects that are truck accessible, that do not require concrete backfill and allow it to reuse the spoils for backfill or spread out on location.

Another reason costs can vary significantly from project to project is due to the time of year and location. SDG&E often deals with elevated fire weather conditions which requires a dedicated fire watch crew to be present at each location where there is work happening that can be a fire risk. In some cases, SDG&E has multiple dedicated fire watch crews on a project as there may be multiple civil or electric crews working at different locations at the same time on the same project. Some locations are also so remote that the drive time from the staging yard to the site can take a significant amount of time out of each workday that the crew may work longer hours and/or over the weekend, including Sundays, thus increasing overtime hours for the construction crew and all other support services (e.g., traffic control, environmental monitors, etc.). In some cases, generators are used due to the remote nature of some customers and the lack of ties with other circuits in SDG&E's service area. Generators require special protection schemes, equipment, and resources to adequately plan, deploy, setup, monitor, and tear-down which increase the installation costs.

Lastly, construction costs can vary depending on the crew building the project and issues encountered during construction that were not anticipated during design. SDG&E currently uses four primary construction contractors who perform the electrical construction and typically sub-contract the civil work (e.g., pole hole and anchor digging), helicopter, traffic control and dedicated fire watch. SDG&E also uses internal electric construction teams who typically contract out the helicopter, traffic control, dedicated fire watch and civil work (pole hole and anchor digging). Based on SDG&E's experience with its traditional hardening program, 75% of the work is performed by contractors and 25% by internal crews. The costs between external and internal crews can vary depending on the work scope, location (rural versus very rural), methods of construction (e.g., truck accessible versus non-truck accessible), time of year (e.g., fire season and non-fire season and wet weather versus dry), and issues encountered during construction. Larger projects (typically 20 or more poles) that are not assigned to an internal crew are sent out to bid with the four prime construction contractors and often bundled together on the same circuit to gain economies of scale. SDG&E has determined that its ideal bid size is 100-200 poles; however, some bids have been significantly greater (e.g., approximately 1,400 poles and over 60 projects) and some can be much smaller. The size of bids can change significantly depending on the location of a project, time of year, and schedule of the project. SDG&E also sees changes with pricing due to competition for construction resources with the other utilities in the state and this can drive-up costs depending on the volume of work and timing with other projects statewide.

PacifiCorp:

CC Unit Cost Make Up:

As included in its 2021 WMP Update Change Order filed November 1, 2021, PacifiCorp has historically broken down the costs of covered conductor into four main categories: Design, Materials, Construction, and Program Management. However, to better align with other utilities, and avoid confusion, for the purposes of this report, PacifiCorp reports the costs of covered conductor in the six main categories. These six categories are described below.

1. Labor (Internal) – Internal labor charged directly to the project including project managers, project support staff, engineers, and field personnel.

2. Materials – All materials installed as part of covered conductor projects.

3. Contractor – Contracted services which are primarily design, estimating, permitting, vegetation management, and construction labor.

4. Overhead – Costs allocated to covered conductor projects such as surcharges for material handling and engineering overheads.

5. Other – Direct costs not covered in one of the other categories.

6. Financing Costs – AFUDC charges on the projects.

Cost Drivers:

PacifiCorp has identified five main cost drivers for the installation of covered conductor. The cost drivers are discussed below in terms of cost increases that have been experienced, highlighting how impactful these components can be on the overall project cost.

Access – PacifiCorp includes costs for required access to facilitate project construction in covered conductor projects charged to the work order. These costs may include vegetation clearing, road construction, or other site preparation activities. These costs will typically be included in the contractor total for purposes of this cost analysis as this work is predominantly contracted. Additionally, these costs can also range significantly between projects based on the specific location and terrain where work is conducted.

Pole Replacement – PacifiCorp evaluates all poles for strength and clearance using PLS CADD. Poles are then selected for replacement for the following reasons: insufficient strength to accommodate covered conductor, insufficient minimum clearance, relocation is required, or not constructible in current state. Through 2021, the average pole replacement rate has ranged from 2 to 22 per mile leading to significant variability in the per mile job cost. Pole replacements also significantly impact labor and material costs (as described below) due to the change in scope of the project. Current cost forecasts assume 20 poles per mile will need to be replaced. Additionally, nearly all poles identified are replaced with non-wood fire resistant materials (predominantly fiberglass) at a greater cost than like-for-like replacement with wood.

Construction Labor – As included in its 2021 Change Order, PacifiCorp experienced significantly higher than anticipated labor costs in 2020 and 2021 based on regional contract rates, construction complexity/time, and overtime requirements to meet project deadlines. Current cost forecasts indicate that this increase will continue in 2022 and future years.

Materials – As included in the Company's 2021 Change Order, PacifiCorp also experienced additional material costs due to the number of pole replacements. Currently, incremental pole replacements add approximately $3,500 per pole in material costs alone. Additionally, supply chain constraints in 2021 resulted in the need for expedite fees, crew re-mobilization costs, and/or use of alternate materials at higher costs.

Permitting – As included in the Company's 2021 Change Order, significant cost increases have been experienced for locations requiring access into seasonal wetlands and transmission under build projects. Future projects include environmentally sensitive areas that have been in National Environmental Policy Act (NEPA) or CEQA review with high environmental review costs.

Based on the cost drivers discussed above, PacifiCorp anticipates higher costs for projects in 2022 and beyond.

BVES:

CC Unit Cost Make Up:

The following costs are charged to project work orders: Design, materials, construction labor and overhead cost. BVES contracts out most of the work with a BVES Field Inspector overseeing the whole project. The design consists of BVES contractor performing field visits, wind loading calculations, developing the design and assembling the material lists. BVES purchases the materials and its contractor does the construction. The overhead costs consist of BVES internal groups. The capital cost per circuit mile are based on a double circuits' area in 2021.

Cost Drivers:

BVES service area is in mountainous terrain at approximately 7,000 ft elevation and consists of a 34.5 kV Delta 3-wire system and a 4.16 kV Wye ground 4-wire system. For the 34.5 kV system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as a secondary source of covered conductor. For the 4.16 kV 3-phase system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as the secondary source of covered conductor. In addition, BVES uses the 4.16 KV (2 or 1) phase system 1/0 ACSR covered conductor. When constructing covered conductor, BVES follows the CPUC's GO 95 Rule 43.1 Grade A Heavy Loading District Construction Standard (Grade A Standard). Based on the Grade A Standard, new poles are required to have a safety factor of 4.0 whereas an existing pole safety factor is 2.67. BVES and BVES's contractor are required to wind load each pole with 6lb/ft wind speed + 0.5 inches of ice. Due to the higher elevation and Grade A standard, BVES is required to replace a pole with a larger size pole to meet the required safety factor. These large poles have a much higher cost than a standard size pole. BVES replaced approximately 70% of its poles per mile of covered conductor installation. The installation and material costs of the replacement poles is one driver that has increased costs for BVES covered conductor projects.

Liberty:

CC Unit Cost Make Up:

Liberty's covered conductor program is relatively new and limited in scope compared to the other utilities. Liberty first piloted covered conductor projects in 2020 in select areas that already needed line upgrades because of asset age and condition, and later focused on projects that targeted short line segments in HFTD areas, had reliability issues, and were in remote areas. An average of recent covered conductor projects amounted to less than one circuit mile per project and only a total of eleven miles of covered conductor were installed over the last two years. Liberty's covered conductor work is substantially less compared to, for example, SCE's approximate 1,000 miles of covered conductor installed each year.

Liberty's covered conductor unit costs will vary depending on the terrain, number of poles replaced, type of conductor installed, project design and permitting requirements, and amount of vegetation management work required for the job order.

Liberty's covered conductor capital costs per mile is made up of the following six major cost categories:

1. Labor (internal) – Internal Labor represents Project Management, Engineering, Operations, Arborists and Line Crews dedicated to the capital job, and cost of removal.

2. Materials – Materials includes poles, crossarms, insulators, down guys, anchors, transformers, hardware, and covered conductor wire purchased through Liberty supply chain operations.

3. Contractor – Contract charges are for construction contractors and professional services to design and execute project scopes. Contract costs also include line clearance qualified tree crews needed to prune and remove trees along the covered conductor line route.

4. Overheads – Overheads are allocated to active job orders monthly based on capital spend. At Liberty, this could include indirect labor, A&G, capital overheads, fleet, and small tools allocations.

5. Other – Other is reserved for taxes applied to the job.

6. Financing Costs – Financing costs capture AFUDC accumulated costs in the covered conductor job order.

Cost Drivers:

Liberty's project life cycle ranges from 18-36 months depending on project scope and permitting complexity. There are many factors that may impact the total project life cycle and costs, including permitting and environmental requirements, easements, geography and terrain, and construction resource availability. A major cost driver for Liberty is the contractor costs for construction in its service territory. Projects typically take longer to construct because of the mountainous terrain and require more costly construction methods like helicopter use, dewatering, hard rock excavation and hand digging. Other factors include permitting, weather, and environmental restrictions that will limit scheduling flexibility and reduce productivity, causing construction costs to increase.

Conductor Type – Liberty has two covered conductor designs that vary depending on project site access and terrain. These include 14.4 kV delta Aerial Spacer Cable (ACS) and tree wire solutions at this voltage level. In addition, Liberty has piloted the use of tree wire solution on its 12.5 kV grounded Wye system. Liberty selects the two different system options based on installation and maintenance considerations of the two solutions.

The ACS solution has 2 or 3 covered conductors supported by a steel messenger. The framing for ACS includes brackets that hold the messenger under tension and for the current carrying conductors at full sag, or zero tension. Installing and maintaining spacers requires a bucket truck, however, if accessibility is an issue, crews might require a Bosun Chair to access the line, adding to the costs.

The tree wire solution includes various sizes of covered wire such as a 1/0, 2/0, or 397 kcmil AAC. The ACS solution projects have installed 1/0AA wire with 1-052 AWA messenger and 1/0 AAC with 6AW messenger. Tree wire is installed with framing similar to bare conductor wire in an open-crossarm configuration for framing and installation. Tree wire is the preferred solution in areas with limited bucket truck access. Conductors are sized based on circuit load for both solutions. Wind and Ice loading are concerns in the Liberty territory, so Liberty does not utilize conductors smaller than 1/0.

Location – A vast majority of Liberty's service territory is in HFTD Tier 2 and Tier 3. In the initial phases of its covered conductor program, Liberty selected areas of its service territory based on local knowledge of the wildland/urban interface, locations of high fire threat districts, remoteness of overhead lines, and the age and condition of the infrastructure. Areas were also chosen based on their accessibility and egress options during an emergency. Most of Liberty's covered conductor projects are in Tier 2 and Tier 3 at elevations between 6,200 to 7,500 feet over rugged, rocky terrain with limited seasonal access. Projects typically utilize helicopter pole sets and crews are tasked with digging pole holes with pneumatic tools by hand versus with trucks with augers. Pole holes take days versus hours to excavate, increasing labor hours and costs.

Pole and Asset Replacements – Most of the covered conductor projects Liberty has designed and constructed have required a significant number of pole replacements per circuit mile. When replacing existing poles, Liberty uses taller and larger class poles. This is due to new loads and increased weights of the covered conductor, as well as the age of existing infrastructure. Projects include installation of poles, insulators, crossarms, anchors (rock anchors), down guys, transformers, and switches. One example is the Lily Lake covered conductor project that required 50 pole replacements for the approximately two miles of covered conductor installed. The terrain at Lily Lake is remote and characterized by massive, expansive boulder fields; making pole hole digging a very labor-intensive operation. Most of the work was conducted by hand crews and helicopters due to the remote terrain.

Economies of Scale – Compared to SCE and PG&E, that have thousands and hundreds of covered conductor circuit miles installed, Liberty has limited contract resources available during its construction period. Liberty's ratio of miles installed when compared to utilities with significantly more miles installed likely leads to higher contract costs on a per mile basis. This factor has likely contributed to Liberty's higher covered conductor cost per circuit mile.

Construction – Liberty's primary construction window is from May 1st to October 15th due to weather and TRPA (Tahoe Regional Planning Agency) dig season restrictions. The construction window also coincides with seasonal tourism, a high number of Red Flag Warning (RFW) days, and during the typical fire season that further limits construction efforts and effects costs. These restrictions also constrain resources and adds a premium on labor during construction season.

In 2021, Liberty's prime construction season was impacted by fires in Northern California. For example, the Tamarack fire in Markleeville required Liberty to utilize all internal and contract resources to respond to the fire and restore power. This was a 3- to 4-week impact where contractors working on covered conductor projects had to be re-assigned to respond to the fire. Liberty has also experienced extremely poor air quality due to area fires with Particulate Matter (PM) 2.5 > 500 ug/m^3. The poor air quality frequently interrupted construction causing increased mobilization and demobilization costs. The poor air quality impacted project schedules by approximately three to four weeks with no workdays when AQI was +500 in the Tahoe Basin. Finally, the Caldor fire forced evacuations in South Lake Tahoe, where the majority of Liberty's covered conductor projects were located further impacting construction costs.

Vegetation Management – Liberty's service territory is in a high elevation and mountainous terrain that is densely forested, averaging over one hundred trees per mile within maintenance distance of the conductor given recent 2020 LiDAR data. Vegetation management inspectors and tree crews often need to access work sites on foot while carrying tools and equipment resulting in much higher labor costs compared to typical work areas. In addition, due to the robust tree canopy in the Tahoe region, tree crew cost per circuit mile of construction has increased significantly due to SB 247 labor rate increases. Tree removals and pruning costs are unique to Liberty's service area and will increase the overall covered conductor project costs.

Next Steps:

In 2022, the utilities plan to continue this sub-workstream and will further discuss and document covered conductor recorded/estimated unit costs and cost drivers as well as assemble and compare initial unit costs for alternatives. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Conclusion:

This report provides descriptions of the progress of this Joint IOU effort to better understand the long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives). The utilities have made progress on each sub-workstream and describe plans for 2022 to improve the data and analyses that have been compiled, including assessing methodologies that can be employed across all utilities to improve comparability. These efforts continue to show that covered conductor has an effectiveness between approximately 60% and 90% at reducing the drivers of wildfire risk. Additionally, the report shows covered conductor is effective at reducing the impacts of PSPS in comparison to bare conductor systems. The alternative analyses also present high-level assessments of select alternatives in comparison with covered conductor at reducing PSPS impacts. The utilities look forward to continuing these efforts in 2022 and providing an update in their 2023-2025 WMPs.

Utility #: PG&E-21-10

Issue title: Insufficient pace of expulsion fuse replacement plan.

Issue description: The pace of PG&E's current program for expulsion fuse replacements is not proportional to those of SDG&E and SCE.[17] *This is especially problematic given PG&E's larger service territory.*

Remedies required and alternative timeline if applicable: PG&E must:

1) *Demonstrate that it is replacing expulsion fuses with fuses that reduce wildfire risk at a speed that adequately addresses risk;*

2) *Explain any current limits or constraints on the scope of PG&E's expulsion fuse replacement program; and*

3) *Increase the pace of its expulsion fuse replacement program, provided reasonable constraints do not limit such expansion.*

Response to PG&E-21-10:

PG&E provided information in response to the items requested in this remedy in our Progress Report. PG&E is providing the following additional update information.

1) PG&E's 2021 WMP commitment was to replace 1,200 non-exempt fuses in 2021. We have completed this commitment by replacing 1,200 units by November 18, 2021. Work has continued through the month of December and at the end of year, PG&E has replaced 1,429 non-exempt fuses in 2021. For 2022, PG&E has increased the target to 3,000 locations where non-exempt fuses will be switched to exempt fuses.

2) No update

3) Our current plan for 2022 is to remove 3,000 non-exempt fuses/ cutouts identified on distribution poles in HFTD areas or HFRA..

Because PG&E has provided the requested information and its plan for expulsion fuse replacements in 2022, we understand that this remedy is closed with the 2022 WMP submission.

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17 Cal Advocates' Comments state at p. 36: "PG&E has approximately 22,000 expulsion fuses in HFTDs and forecasts replacing about five percent of them in 2021" which is approximately 1,100 fuses. At this rate, it will take PG&E nearly two decades to remove all the expulsion fuses from the HFTD. By comparison, BVES replaced 2,200 in 2020, which is more expulsion fuses than PG&E in 2020, although PG&E's service territory is two thousand times larger than BVES. In 2021, SDG&E replaced "3,179 (with a focus in Tiers 3 and 2 of the HFTD), bringing the total replaced to 5,669 out of the 11,000 total populations of such fuses in the HFTD" (according to SDG&E's 2021 WMP Update, p. 197). SCE is replacing "13,000 locations by the end of 2022 (cumulative from the inception of the program in 2018)" (according to SCE's 2021 WMP Update, p. 216).

Utility #: PG&E-21-11

Issue title: Insufficient detail regarding installation of expulsion fuses in HFTD areas.

Issue description: PG&E continues to install non-exempt expulsion fuses, which are considered to be fire hazards, in HFTD areas. PG&E installed approximately 71 nonexempt expulsion fuses in the HFTD 2019 and 44 fuses in 2020. PG&E states that it is acceptable to install non-exempt expulsion fuses in the HFTD under certain circumstances but does not detail whether the installed fuses were installed in those circumstances.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Explain the circumstances under which it installed non-exempt expulsion fuses in HFTD areas; and*

2) *Clarify if any of the new expulsion fuses it is installing in the HFTD in 2021 and beyond are nonexempt fuses.*

Response to PG&E-21-11:

PG&E provided a response to Part 1) in our Progress Report.

2) For 2021 and subsequent years, a non-exempt fuse would only be installed in the situations as outlined in the Progress Report. In 2021, there were 69 non-exempt fuses installed in HFTD areas due to the situations described in the Progress Report. In these locations, PG&E adheres to California Public Resource Code (PRC) Section 4292 to clear vegetation on all non-exempt poles.

Utility #: PG&E-21-12

Issue title: Failure to adequately track copper conductor replacements and insufficient detail regarding targeting replacements to highest risk areas.

Issue description: While PG&E has identified that copper (CU) conductor poses a high risk to its system due to its high incidence of failure PG&E does not currently track its completed CU reconductoring projects. Additionally, PG&E's CU reconductoring program extends outside of the HFTD, but PG&E does not provide sufficient evidence that its CU reconductoring plan targets its highest risk circuits.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Develop a workplan to target and track CU reconductoring projects; and*

2) *Demonstrate that it is targeting its CU reconductoring projects to its highest risk circuits, including justification for any projects outside of the HFTD.*

Response to PG&E-21-12:

PG&E continues to perform conductor replacement under the Non-HFTD Replacement Program and the System Hardening Program as described in the Progress Report. Since these are ongoing programs, and PG&E described our workplan and demonstrated our approach to CU reconductoring projects in the Progress Report, we understand this remedy is closed with the submission of the 2022 WMP.

Utility #: PG&E-21-14

Issue title: Inadequate transparency of system hardening plan.

Issue description: PG&E provides limited detail regarding its short-term system hardening plan and does not include its LT system hardening plan. Additionally, PG&E's July 21, 2021, press release[18] *regarding its intention to underground 10,000 miles of power lines indicates that the system hardening plan and initiative selection process that PG&E presents in its 2021 WMP Update may change. PG&E has not provided any potential modifications to its 2021 WMP Update related to this press release. While Energy Safety is generally supportive of PG&E's ambition to aggressively reduce its wildfire risk, PG&E must provide additional detail on its Short-Term and Long-Term Plans (LTP) for grid hardening, as well as an update on its progress.*

Remedies required and alternative timeline if applicable: PG&E must:

1) *Provide its short-term*[19] *system hardening plans, including the following details for each planned project (via comprehensive list and GIS files):*
   a) *Location;*
   b) *Initiative type (covered conductor, undergrounding, line removal, etc.);*
   c) *Status of the project (scoping, design permitting, etc.);*
   d) *Relevant CPZs;*
   e) *Planned length; and*
   f) *Risk-type identified for prioritization of the project (top 20 percent of risk buydown curve, fire rebuild, PSPS mitigation, public safety specialist identified, or non-risk related)*
2) *Provide its LT system hardening plan regarding:*
   a) *Estimated rate of system hardening per year;*[20] *and*

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18 "PG&E Announces Major New Electric Infrastructure Safety Initiative to Protect Communities from Wildfire Threat," July 21, 2021: https://investor.pgecorp.com/news-events/press-releases/press-release-details/2021/PGE-Announces-Major-New-Electric-Infrastructure-Safety-Initiative-to-Protect-Communities-From-Wildfire-Threat/default.aspx (accessed July 28, 2021).

19 "Short-term" defined as a project that has entered the scoping process or planning phase, including the 1,120 miles identified for system hardening from 2021-2023, per PG&E's Redlined 2021 WMP Update, pdf p. 653.

20 If such differs from the 450 to 500 miles per year provided in PG&E's Redlined 2021 WMP Update, PDF p. 653.

b) *If/how PG&E plans to increase its resources to allow for an accelerated pace of system hardening.*

3) *Explain how, if at all, PG&E's recently announced undergrounding plan:*

   a) *Changes its decision-making framework for initiative selection for individual circuit segments;*[21] *and*

   b) *May cause delays deferrals, and/or cancellation of research and/or deployment of advanced technology mitigations.*

4) *Provide an update on its completed system hardening efforts through November 1, 2021.*

5) *Additionally, if PG&E is moving forward with its stated intention to underground 10,000 miles of power lines, PG&E must provide detail in its 2022 WMP Update on the decision to underground and plans for such undergrounding.*

<u>Response to PG&E-21-14</u>:

1) We are providing Attachment 2022-02-25_PGE_2022_WMP-Update_R0_Section 4.6_Remedy 21-14_Atch01, which has updated information since the Progress Report was submitted as of January 31, 2022.

   A few of the columns of information provided in the attachment require some additional detail. First, Column L (2021 Miles Installed) counts toward our 2021 System Hardening target of 180 high risk miles. Column K (2020 Miles Installed) represents system hardening projects that started in 2020 but finished in 2021.It does not represent all system hardening projects that were completed in 2020. Column M (2022 Forecast Miles) represents the system hardening miles that would count toward our 2022 System Hardening target of 470 high risk miles. The forecasted miles are based on the most current available data and may change if projects encounter delays for permitting, resource availability, and other issues. Thus, the miles in Column M are subject to change.

   Second, PG&E has included Column V (Circuit Protection Zone) and Column W (2021 Risk Rank). These columns contain information regarding CPZ designations and the ranking of CPZs in the current risk models. Please note that the 2021 Risk Rank is based on the 2021 WDRM v2.

   Third, PG&E includes in our System Hardening Program the removal of idle line facilities. In Column X (Project Type), when a project is to remove an idle line, since Column C (Category) already indicates idle line facilities, this is not repeated again in Column X and the row in Column X for idle line facilities is left blank.

   Finally, Columns N and O provide forecasts of system hardening work for 2023 and 2024~~, respectively. The very small amount of undergrounding work scheduled for~~

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[21] As described in PG&E's presentation to WSD on May 21, 2021 and summarized in a footnote above.

~~2024 was originally planned for 2023 but has a longer dependency lead time. We have not yet started selecting undergrounding locations for 2024 workplans.~~ as of January 31, 2022. In addition, in response to Critical Issue RN-PG&E-22-04 Remedy #1, we have updated our planned undergrounding work for 2023-2026 in Attachment 2022-07-26_PGE_22-04_RNR_R3_Atch01CONF or 2022-07-26_PGE_22-04_RNR_R3_Atch01_Redacted. Please see that attachment for additional information.

PG&E continues to refine and update our System Hardening Program workplan for these years and thus additional System Hardening projects may be added or projects listed may be removed from the workplan. ~~Columns N and O represent our most current forecast but is subject to change as we continue to review and refine our System Hardening Program workplan for these years.~~

2) See Section 7.3.3.17.1, in particular the responses to Question 4 and Question 5. Please see our responses to Critical Issues RN-PG&E-22-04 and RN-PG&E-22-03 for additional information regarding planned undergrounding work for 2023-2026.

3) See Section 7.3.3.17.1, in particular the response to Question 5. See also Section 7.3.3.16 for further information regarding PG&E's distribution undergrounding plans. Please see our responses to Critical Issues RN-PG&E-22-04 and RN-PG&E-22-03 for additional information regarding planned undergrounding work for 2023-2026.

4) The information responsive to Question 4 is included in 2022-02-25_PGE_2022_WMP-Update_R0 _Section 4.6_Remedy 21-14_Atch01 Column L. This information reflects the final completed miles in 2021.

5) See Section 7.3.3.16. Please see our responses to Critical Issues RN-PG&E-22-04 and RN-PG&E-22-03 for additional information regarding planned undergrounding work for 2023-2026.

Section 5.4: Asset Management and Inspections

Utility #: PG&E-21-17

Issue title: Insufficient evidence of Quality Assurance/Quality Control (QA/QC) for work performed by contractors.

Issue description: Several PG&E internal audits revealed contractors that failed to follow procedures or were unaware of the correct procedures that needed to be followed. PG&E's response to cases where the vendor was unaware of or did not follow procedures often amounted to a reminder of how procedures should have been followed. In most cases, PG&E did not further investigate the quality of other work the same vendor had performed, nor require full retraining on the topic.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Demonstrate that it is tracking the quality of work of contractors performing asset management and inspection work.*

2) *Describe how it is addressing underperforming asset management and inspection contractors; and*

3) *Describe how it is expanding quality control (QC) of work performed by asset management and inspection vendors, including additional QCs for those with a history of flawed work.*

Response to PG&E-21-17:

The key activities planned are the expansion of the QC Desktop Review program in 2022 by adding two additional inspection methods – Substation and Aerial. These QC methods are currently in development and are anticipated to be implemented next year. A QC Field Review process is being established for Transmission and Distribution Overhead inspection methods. This new process will be implemented in Q1 2022.

To better utilize and ensure actionable outcomes are being derived from the quality data collected via the Desktop QC program and other quality monitoring, QC will be adding a permanent standalone program to its Quality Programs portfolio in 2022. The program's goal is to lead and manage a continuous improvement quality feedback process within System Inspections. The feedback process inputs will be inclusive of both internal and contract inspector work.

QC is also partnering with Electric Operations (EO) Vendor Performance Management team to develop Quality Key Performance Indicators and Vendor Scorecards. This project should be implemented in early 2022.

Section 5.5: Vegetation Management and Inspections

<u>Utility #</u>: PG&E-21-18

<u>Issue title</u>: Minimally planned maturity of VM program.

<u>Issue description</u>: PG&E has increased the scale of its VM program but does not foresee maturing five of six VM Maturity Model capabilities. PG&E's planned end WMP cycle VM maturity is 1, up from 0.7 in 2020. Comparatively, SCE and SDG&E have a planned end WMP cycle VM maturities of 3 and 3.3 respectively (see Figure 5.5.b, below). Additionally, PG&E does not provide adequate discussions in the reoccurring subsection "5. Future improvements to initiative" nor in response to Quarterly Report Action PGE-25 (Class B), subpart 1. PG&E must create a LT VM maturation strategy and establish clear goals and targets to prioritize work and monitor progress towards its risk-reduction goals.

<u>Remedies required and alternative timeline if applicable</u>: PG&E must:

1) *Reach a maturity of at least 1 for capabilities 24 "Vegetation grow-in mitigation" and 25 "Vegetation fall-in mitigation" by the end of 2023;*

2) *Clearly define goals and targets to reach each level of maturity for capabilities 21-26;*

3) *Include a timeline for completion of the goals and targets from (1); and*

4) *Provide a LT vision for each VM initiative in Subsection 5 "Future improvements to the initiative" (or similar) including any relevant timelines.*

<u>Response to PG&E-21-18</u>:

1) PG&E has reached a maturity level of at least 1 for Capabilities 24 and 25. Please see additional details in our response to Q2 below.

2) Please see defined goals and targets to reach each level of maturity for Capabilities 21 - 26 below:

<u>Capability 21 – Vegetation inventory and condition assessments</u>

<u>Goals</u>: This level of maturity will be obtained by continued enhancement of our Tree Assessment Tool (TAT). The TAT is undergoing revision/improvement to its accuracy. This accuracy improvement-based revision is anticipated to be complete in 2022.

<u>2021 Progress Update</u>: We are currently on-track to complete this goal in 2022. An evaluation of the TAT is currently in progress and is expected to be completed as part of the Targeted Tree Species Study, which will be completed by March 31, 2022.

<u>Capability 22 – Vegetation inspection cycle</u>

<u>Goals</u>: PG&E will continue to perform a second inspection in many parts of our service territory, namely HFTDs, that are at higher risk of tree mortality and/or wildfire risk. The implementation of performing additional inspections will move PG&E well beyond the

expectation of meeting minimum regulatory requirements, with more frequent inspections for highest risk areas.

2021 Progress Update: Mid-Cycle inspections are ongoing on Transmission VM and tree mortality inspections on Distribution VM programs and will continue.

Capability 23 – Vegetation inspection effectiveness

2021 Progress Update: This effort is ongoing. For additional detail See Section 7.3.5.6.

Capability 24 – Vegetation grow-in mitigation

2021 Progress Updates: PG&E must meet or exceed minimum regulatory clearances during all seasons to maintain an annual pruning cycle. PG&E plans on maintaining an annual pruning cycle through 2023, and therefore, will continue to meet or exceed in many circumstances the regulatory clearance.

Capability 25 – Vegetation fall-in mitigation

2021 Progress Update:

In an effort to improve upon EVM practices in 2021, PG&E standardized the method for measuring and identifying strike trees for the pre-inspection and work verification teams. The goal of this process improvement was to align the pre-inspection process to the Work Verification. This alignment is showing a reduction in the amount of rework.

Capability 26 – QA/QC for vegetation maintenance

2021 Progress update: QA/QV met its target of conducting approximately 2,000 audits/reviews in 2021.

Items (3) and (4)

TABLE PG&E-REMEDY-21-18-1:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE

Initiative #	Additional Information on Long-Term Plans
7.3.5.1	Please see Section 7.3.5.1 of the 2022 WMP for long-term plans regarding this initiative.
7.3.5.2	Please refer to section 7.3.5.2 for additional information on future improvements for this initiative. For additional information related to LiDAR, please see Section 7.3.5.7 concerning LiDAR Inspections of Vegetation Around Distribution Electric Lines and Equipment.
7.3.5.3	Please refer to section 7.3.5.3 for additional information on future improvements for this initiative. For additional information related to LiDAR, please see Section 7.3.5.8 concerning LiDAR Inspections of Vegetation Around Transmission Electric Lines and Equipment.
7.3.5.4	Responding to Red Flag Warning days or other elevated fire weather events are considered to be reactive work due to its unpredictable nature. Because of this, PG&E will maintain the current process for responding to these urgent conditions and will continue to evaluate the execution of work for opportunities to improve.
7.3.5.5	The scope of this initiative has changed for 2022. This section now addresses pole clearing, debris, and the Wood Management program. Please see Section 7.3.5.20 of the 2022 WMP for long-term plans regarding the UDS program. Long-term, PG&E plans to complete Wood Management work on opted-in parcels following 2020-2021 wildfires. Once this work is completed, PG&E plans to achieve a steady state of its Wood Management program in its effort to mitigate wood directly following VM work. In addition, the Wood Management program will be offered across all VM programs. Please see Section 7.3.5.2 and 7.3.5.3 of the 2022 WMP for long-term plans regarding pole clearing.
7.3.5.6	Please refer to Sections 7.3.5.2 (Detailed inspections of vegetation around distribution electric lines and equipment), 7.3.5.3 (Detailed inspections of vegetation around transmission electric lines and equipment), and 7.3.5.13 (QA/QV of Inspections) for future improvements regarding this initiative.
7.3.5.7	Please refer to section 7.3.5.7 for more information on future improvements for this initiative.
7.3.5.8	Please refer to section 7.3.5.8 for more information on future improvements for this initiative.
7.3.5.9	Please refer to Section 7.3.5.2 for more information on future improvements for this initiative.
7.3.5.10	Please refer to Section 7.3.5.3 for more information on future improvements for this initiative.
7.3.5.11	Please refer to Section 7.3.5.2 for more information on future improvements for this initiative.
7.3.5.12	Please refer to Section 7.3.5.3 for more information on future improvements for this initiative.

TABLE PG&E REMEDY-21-18-1:
LONG TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Additional Information on Long-Term Plans
7.3.5.13	Electric Quality Management/Quality Assurance Vegetation Management (QAVM) and Quality Verification Vegetation Management (QVVM) are in the process of moving to a mobile application for completing all VM program audits. QM's 5-year plan is to adopt the ESRI Suite of products including Survey123/Field Maps/GeoHub/Workforce to manage sampling, work allocation, audit completion and data management. The 5-year plan currently is to further mature the Data Flow for all programs including QAVM and QVVM and continue to evaluate alignment with Veg Operations. QM's annual audit plan is developed in October for the upcoming year, then is revised as needed to meet changes in prioritization for EOs, including break-in audits needed to address agency findings or findings from an Internal Audit. A deeper review is conducted in April to provide an opportunity to formally make changes to the audit plan. All audit planning occurs in a tool called P6 which is updated bi-weekly by the QM team. We do not plan audits 5 years in advance.
7.3.5.14	Please refer to section 7.3.5.14 for more information on future improvements for this initiative.
7.3.5.15	Please see Section 7.3.5.2 for long-term plans regarding the TAT.
7.3.5.16	Please refer to Sections 7.3.5.2, 7.3.5.3, and 7.3.5.15 for more information on future improvements for this initiative.
7.3.5.17.1	In 2022, PG&E will inspect 263 Electric Distribution Substations located in non-HFTD areas for purposes of achieving defensible space and fuel reduction beyond Tier 2 and Tier 3 HFTDs. In addition, during routine defensible space inspections of Distribution Substations within Tier 2 and Tier 3 HFTD areas, PG&E will identify and pursue vegetation removal and thinning work on undeveloped privately owned land neighboring PG&E property for further risk reduction purposes.
7.3.5.17.2	In 2022, PG&E will inspect 41 ET Substations in non-HFTD areas to achieve defensible space and fuel reduction beyond Tier 2 and Tier 3 HFTD. In addition, during routine, defensible space inspections of Transmission Substations within a Tier 2 and Tier 3 HFTD, PG&E will identify and pursue vegetation removal and thinning work on undeveloped privately owned land neighboring PG&E property for further risk reduction purposes.
7.3.5.18.1	By 2022, PG&E will complete an evaluation of the sites included in the substation defensible space program to determine the locations where it is feasible and prudent to establish an herbicide treatment program for improved long-term control and abatement of noxious weeds and reoccurring/ regenerating brush species. Starting in 2022, PG&E will establish the herbicide treatment program at each of these locations and will continue the program by reapplying the herbicide at intervals required to maintain control of the targeted species.
7.3.5.18.2	By the end of 2021, PG&E will complete an evaluation of the sites included in the substation defensible space program to determine the locations where it is feasible and prudent to establish an herbicide treatment program for improved long-term control and abatement of noxious weeds and reoccurring/ regenerating brush species. Starting in 2022, PG&E will establish the herbicide treatment program at each of these locations and will continue the program by reapplying the herbicide at intervals required to maintain control of the targeted species.
7.3.5.19	Please refer to Section 7.3.5.19 for more information on future improvements for this initiative.

TABLE PG&E REMEDY-21-18-1:
LONG TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Additional Information on Long-Term Plans
7.3.5.20	The definition for this initiative has changed for 2022. This section now addresses EVM, ROW expansion, and the UDS program. Please see Section 7.3.5.2 of the 2022 WMP for long-term plans regarding the EVM program, Section 7.3.5.3 for ROW expansion, and 7.3.5.20 for the UDS program.

Utility #: PG&E-21-19

Issue title: Delays in achieving mutually agreeable environmental mitigation.

Issue description: PG&E cites delays in reaching mutually agreeable environmental and community impact mitigation efforts that in certain situations result in PG&E seeking court orders.[22] *These delays, judicial or otherwise, can compromise working relationships between the community and state and local environmental agencies and cause further delays to WMP initiatives.*

Remedies required and alternative timeline if applicable: PG&E must show progress on achieving environmental and community impact mitigation agreements with agencies, local governments, and tribal governments. PG&E must consider the development of Operations and Maintenance (O&M) Plans and Memorandums of Understandings with relevant federal, state, and local land managing agencies to facilitate agreed-upon review times of permits and/or VM activities. PG&E must document the outcomes of these efforts and any lessons learned.

Response to PG&E-21-19:

Below, we provide a list of permits that have either been completed or are in progress since the Progress Report was submitted:

Completed:

No additional permits since the Progress Report

In Progress:

1) Undergrounding Habitat Conservation Program (HCP) – This HCP with the USFWS will provide take coverage of endangered federal plant and animal species across the entire service territory for the upcoming 10,000 miles of undergrounding work. We will also include remote grid work as a covered activity under this permit.

2) Tribal Lands – We have started negotiations with several tribes to gain their interest in creating a programmatic agreement or memorandum of understanding (MOU) for work across their tribal lands.

[22] PG&E Revised 2021 WMP Update p. 691.

Utility #: PG&E-21-20

Issue title: Non-inclusion of fire damage attributes in hazard tree assessments.

Issue description: In DR WSD_011, WSD asked PG&E whether fire impact characteristics (char, scorch, etc.) were included in PG&E's TAT. PG&E stated that the TAT "does not include post-fire specific factors such as char, etc. This tool was not developed for, or intended to be used in, post-wildfire response circumstances. When wildfires occur, PG&E performs a hazard tree assessment of the burned area to determine whether trees pose a threat to electric assets and if they should be abated." Contradictorily, PG&E specifically defines the TAT in its WMP as a "Tool that evaluates an individual tree's likelihood of failing and supplies instruction of whether to abate or not abate the tree." It is unclear whether PG&E has another tool, other than its TAT, it uses to perform hazard tree assessments in post-wildfire response circumstances or whether it uses no tool or standard assessment for hazard tree assessments in post-wildfire response circumstances.

Remedies required and alternative timeline if applicable: PG&E must:

1) *Clarify what tool or standard PG&E and its contractors use in post-wildfire response circumstances for hazard tree assessments;*

2) *If such a tool or standard does not already include post-fire specific factors (e.g., crown, bole, and root scorch, char, duff consumption).23 PG&E must include these factors in such tool or standard;*

3) *If such a tool or standard does not exist, PG&E shall develop one to use in post-wildfire response circumstances;*

4) *Provide the training to its staff and contractors in post-fire tree assessments;*

5) *Use such a tool during PG&E's Phase 2 "Non-Imminent Hazard Trees" post-wildfire response;*[24] *and*

6) *PG&E should use such a tool during Phase 1 "Imminent Threat Inspection" as feasible.*

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23 *Factors Affecting Survival of Fire Injured Trees: A Rating System For Determining Relative Probability of Survival of Conifers in the Blue and Wallowa Mountains*, U.S. Forest Service, November 25, 2002.

24 Phase 2 "Non-Imminent Hazard Trees" is described in "WSD-001 Glass Fire," response received March 1, 2021: Under PG&E's emergency operations protocols, there are two phases of VM inspections. The duration of each phase will vary due to timeline dependencies such as CAL FIRE clearance/accessibility, availability of PIs and the volume of damage or fire footprint. Phase 1 – Imminent Threat Inspection: Inspect and eliminate any tree that is actively failing and identify trees that will need to be removed by construction crews to support reconstruction work to restore power. Phase 2 – Non-Imminent Hazard Trees: Listing non-immediate hazard trees for work; this can be done in parallel with Phase 1 if inspectors are available.

Response to PG&E-21-20:

The 2019 Wildfire Response Guidance document was used by the vegetation management department for response to the 2021 wildfires. Opportunities for improvement were identified and a draft VM Wildfire Inspection Guide was developed that contains objective hazard tree assessment criteria. PG&E is planning to complete the final updated document by the third quarter 2022. For additional details, please see Section 7.3.5.21.

Utility #: PG&E-21-21

Issue title: Unknown environmental impact of fire retardant used on a planned basis.

Issue description: PG&E plans to undertake a review of fire-retardant chemicals ahead of the 2021 wildfire season to pilot under its UDS program "pre-treat[ing] ROWs and around equipment in select locations to limit a spark from causing an ignition." PG&E has not determined a LTP for this initiative, considers it a pilot, and has no set targets (e.g., number of circuit miles or acres to be treated with retardant). However, on August 30, 2021, PG&E informed Energy Safety it has been "applying preventative fire retardant on poles and underneath powerlines in high risk areas to reduce the potential of a catastrophic wildfire" to "81 pilot [circuit] miles" (Presentation to the Energy Safety and the CPUC's Safety Enforcement Division from PG&E titled "Public Safety Measures: Addressing Extreme Drought", August 6, 2021) as part of its Preventative Fire Retardant Program (PFRP).[25] Fire retardant is typically used as an emergency measure applied in front of imminent fire and the efficacy and environmental impact of PG&E's PFRP are unknown.

Remedies required and alternative timeline if applicable: PG&E must provide:

1) *Its review of fire-retardant that includes the following: product toxicological and environmental analysis; efficacy analysis; environmental planning and permitting assessment; and the scope of use;*

2) *A report on the objectives and execution of its PFRP in 2021 and its PFRP plan for 2022;*

3) *Quarterly reports regarding the deployment of fire-retardant to the Compliance Division of OEIS per CPUC approved Compliance Operational Protocols. These reports must include where and when the retardant was used, how much retardant was used, and the specific fire-retardant that was used; and*

4) *An RSE value its PFRP.*

Response to PG&E-21-21:

The objective of the 2021 Preventative Fire Retardant Program (PFRP) was two-fold: (1) attempt to apply retardant to high risk circuits to mitigate ignition risk during the peak of the wildfire season; and (2) establish and test the end-to-end process for preventative fire-retardant applications at scale and determine the viability of continued preventative fire retardant applications at scale in 2022. The PFRP established and evaluated a risk prioritization methodology; a screening process to ensure that environmentally and culturally sensitive land, agricultural land, and sensitive receptor locations are precluded from applications; a customer engagement program to seek customer approval for applications; and a tactical retardant application protocol.

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25 Presentation to the Office of Energy Infrastructure Safety and the CPUC's Safety and Enforcement Division from PG&E titled "Public Safety Measures: Addressing Extreme Drought", August 6, 2021.

Between August 13, 2021 and October 15, 2021, the PFRP program applied retardant on poles and underneath conductors, along 12.76 miles of spans in Shasta and Solano counties. Applications were halted as winter storms across the PG&E service territory reduced the wildfire risk. Following the completion of its initial bench scale testing of fire retardants and trial of preventative applications in the field in 2021, PG&E determined that additional environmental testing of retardants in outdoor conditions is necessary during the 2022 wildfire season in order to determine whether it is appropriate to conduct preventative fire retardant applications at scale in subsequent years.

In 2022, additional environmental testing will be conducted to build on the 2021 Bench Scale testing. The following testing will occur:

- Efficacy/Durability Testing – Evaluate if retardants weather differently in actual environmental settings with mixed fuels. Fire retardant will be applied on vegetation in several sample locations within Tier 2 and 3 HFTD areas in the spring of 2022 after the winter rains. The efficacy/durability of the products will be evaluated by collecting field treated vegetation and measuring its combustion characteristics in a laboratory setting.

- Ecological and Human Health Risk Assessments – Evaluate potential human health and environmental impacts from retardant applications. Also, evaluate the impacts of repeated applications of retardants and the impacts of mass loading. This effort will help to answer if there are long term risks with the use of these products and if repeat applications can occur in the future.

- Dissipation Studies – Characterize how the ingredients that compose the products migrate from treated vegetation, to soil, and into soil porewater. Evaluation will include ambient weather conditions. As well as simulated high rain conditions. The results will be used to validate the results of the desktop fate and transport modeling simulations that are performed in support of the risk assessment.

In addition, PG&E has identified the Enhanced Powerline Safety Settings program as being more effective than preventative fire retardant applications in reducing ignition potential during the wildfire season and as such will be looking to rely on that program for mitigation ignition risk in HFTD areas.

Utility #: PG&E-21-22

Issue title: Incomplete identification of vegetation species and record keeping.

Issue description: In Table PG&E-7.3.5-6 on p. 666, PG&E reports that "Oak" and "Pine" are species that have caused >1 percent of several regions' outages. However, these are not tree species, but tree genera. PG&E needs to ensure proper identification of trees to the species level. This specificity will ensure that the "regional species risk values" input to its TAT are updated and accurate. While PG&E does not currently prescribe tree-work based on specific species,[26] *it may choose to do so in the future; in this case, accurate recordkeeping of the species designation is essential.*

Remedies required and alternative timeline if applicable: PG&E must:

1) *Use scientific names in its reporting (as opposed to common names). This change will be reflected in the upcoming updates to Energy Safety GIS Reporting Standard;*

2) *Add genus and species designation input capabilities into its systems which track vegetation (e.g., vegetation inventory system and vegetation-caused outage reports);*

3) *Identify the genus and species of a tree that has caused an outage27 or ignition28 in the Quarterly Data Reports (QDR) (in these cases, an unknown "sp." designation is not acceptable);*

4) *If the tree's species designation is unknown (i.e., if the inspector knows the tree as "Quercus" but is unsure whether the tree is, for example, Quercus kelloggii, Quercus lobata, or Quercus agrifolia), it must be recorded as such. Instead of simply "Quercus," use "Quercus sp." If referencing multiple species within a genus use "spp." (e.g., Quercus spp.);*[29]

5) *Teach tree species identification skills in its VM personnel training programs, both in initial and continuing education; and*

6) *Encourage all VM personnel identify trees to species in all VM activities and reporting, where possible.*

26 PG&E 2021 WMP Update p. 667.

27 WSD GIS Data Reporting Standard Version 2, Transmission Vegetation Caused Unplanned Outage (Feature Class), Section 3.4.5 & Distribution Vegetation Caused Unplanned Outage (Feature Class), Section 3.4.7.

28 WSD GIS Data Reporting Standard Version 2, Ignition (Feature Class), Section 3.4.3.

29 Jenks, Matthew A. (undated, from 2012 archived copy), "Plant Nomenclature," Department of Horticulture and Landscape Architecture, Purdue University, accessed May 18, 2021.

Response to PG&E-21-22:

PG&E will use scientific names for future reporting. Application updates and related communications will be developed and released as part of scheduled enhancements in 2022.

Utility #: PG&E-21-23

Issue title: Inadequate joint plan to study the effectiveness of enhanced clearances

Issue description: RCP Action-PGE-35[30] *(Class A) required PG&E, SCE, and SDG&E to "submit a joint, unified plan" to begin a study of the effectiveness of extended vegetation clearances. PG&E submitted its plan to study the effectiveness of extended vegetation clearance as part of its February 26, 2021, "Supplemental Filing Addressing Remedial Compliance Plan and First Quarterly Report Action Items."*

SDG&E, PG&E, and SCE presented a "joint, unified" plan to Energy Safety on February 18, 2021. While it was apparent the three large utilities had discussed a unified approach, each utility presented differing analyses that would be performed to measure the effectiveness of enhanced clearances. This presentation's content was not included in the February 26, 2021, "Supplemental Filing Addressing Remedial Compliance Plan and First Quarterly Report Action Items."

Energy Safety acknowledges the complexity of this issue; any study performed assessing the effectiveness of enhanced clearances will take years of data collection and rigorous analysis.

Remedies required and alternative timeline if applicable: SDG&E, PG&E, and SCE will participate in a multi-year vegetation clearance study. The objectives of this study are to:

1) *Establish uniform data collection standards;*

2) *Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact);*

3) *Incorporate biotic and abiotic factors31 into the determination of outage and ignition risk caused by vegetation contact; and*

4) *Assess the effectiveness of enhanced clearances.*

In preparation for this study and the eventual analysis, PG&E must collect the relevant data; the required data are currently defined by Energy Safety GIS (GIS Data Reporting Standard for California Electrical Corporations – V2). Table 2 in Section 5.5 of this Action Statement outlines the feature classes which Energy Safety believes will be most relevant to the study. Energy Safety will also be updating the GIS Reporting Standards in 2021, which may include additional data attributes for vegetation-related risk events.

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30 Wildfire Safety Division Evaluation of PG&E's Remedial Compliance Plan can be found here (accessed August 2, 2021): https://energysafety.ca.gov/wp-content/uploads/docs/wmp-2020/pge-rcp-action-statement-20201230.pdf.

31 Biotic factors include all living things (e.g., an animal or plant) that influence or affect an ecosystem and the organisms in it; abiotic factors include all nonliving conditions or things (e.g., climate or habitat) that influence or affect an ecosystem and the organisms in it.

Response to PG&E-21-23:

The utilities have prepared the following joint response providing an update for this remedy.

SDG&E, PG&E, and SCE (jointly, investor-owned utilities or IOUs) have begun collaboration on a vegetation clearance study. This is expected to be a multi-year effort which will benchmark vegetation management practices and data collection methodologies across IOUs in order to help develop uniform data standards. Bi-weekly meetings began on September 9,2021 and eight meetings have been held to date, with attendees from the IOUs and Energy Safety at each meeting.

The IOUs are focused on addressing the required remedies of this study, which include:

- Establish uniform data collection standards
- Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact)
- Incorporate biotic and abiotic factors21 into the determination of outage and ignition risk caused by vegetation contact
- Assess the effectiveness of enhanced clearances

SDG&E, PG&E, and SCE (jointly, investor-owned utilities or IOUs) have begun collaboration on a vegetation clearance study. This is expected to be a multi-year effort which will benchmark vegetation management practices and data collection methodologies across IOUs in order to help develop uniform data standards. Bi-weekly meetings began on September 9,2021 and eight meetings have been held to date, with attendees from the IOUs and Energy Safety at each meeting.

Initial meetings began with each utility discussing their existing data collection standards and early analysis of enhanced vegetation clearances. The IOUs discussed definitions being used and began to standardize definitions including “enhanced clearance,” “inventory tree,” “tree-caused risk event,” and “post-trim clearance.” The different types and methods of creating a cross-utility database of tree-caused risk events were reviewed. There are pros and cons to the various methods discussed, with more work to be completed in the future on the format and location of this database.

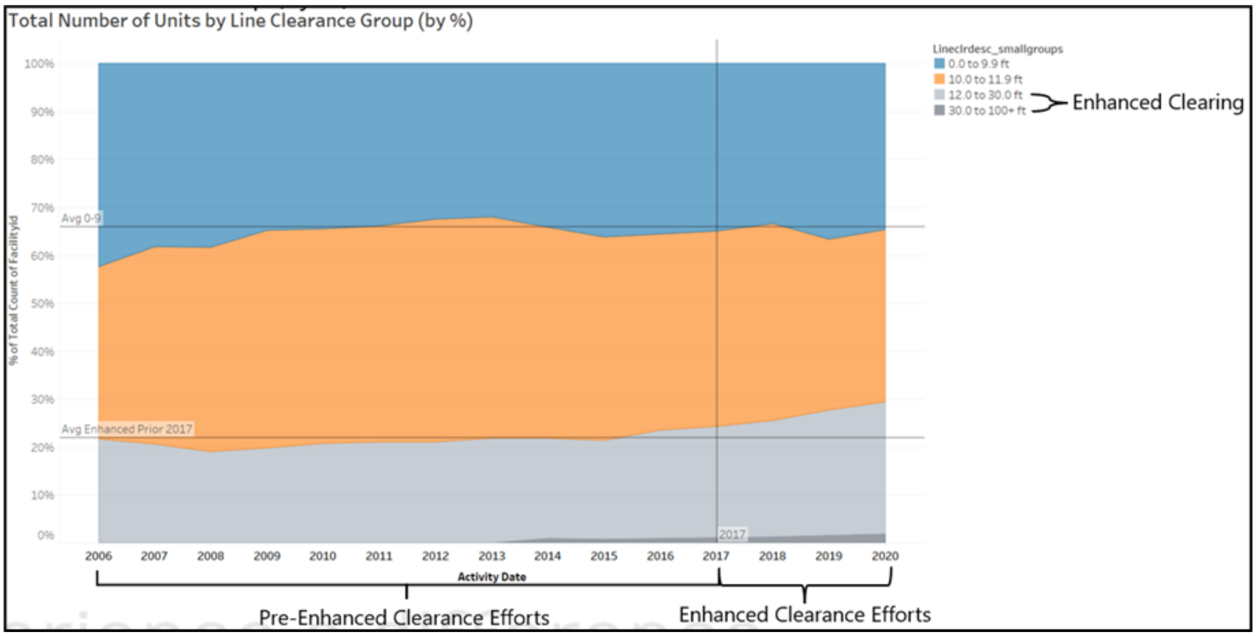
The most recent meetings, which took place after the November 1, 2021 Progress Report, focused on each IOU demonstrating its current analysis around the effectiveness of enhanced clearances.

Initial analysis focus on outage/interruption events as these are precursors to ignition events. Ignition data does not have a sufficient population sample size to evaluate at this time. These initial analyses are presented below for each IOU:

SDG&E:

Initial analysis performed by SDG&E studied the relationship between line clearance and vegetation related outages on the system. The outages being studied are related to unplanned forced outages, excluding instances where the line is de-energized for safety to allow crews to work in the area. The IOUs have defined enhanced clearance as trimming the vegetation at least 12 feet from the energized conductor. Enhanced clearance efforts ramped up beginning in 2017, as shown in the graph below where the percent of SDG&E's inventory trees trimmed to enhanced clearances increases to near 30%.

FIGURE PG&E-REMEDY-21-23-1:
TOTAL NUMBER OF UNITS BY LINE CLEARANCE GROUP (BY %)



SDG&E sees an increase in average line clearance over time, with a related relative decrease in vegetation related outages over time. This decrease in vegetation related outages will likely lead to fewer events that could result in an ignition leading to a wildfire. Data from 2006-2016, the pre-enhanced clearance timeframe, compared to data from 2017-2020, the post-enhanced clearance timeframe, show that vegetation-related outages have decreased by thirty-eight percent since these enhanced clearance efforts began.

FIGURE PG&E-REMEDY-21-23-2:
VEGETATION-RELATED OUTAGES VS. AVERAGE LINE CLEARANCE

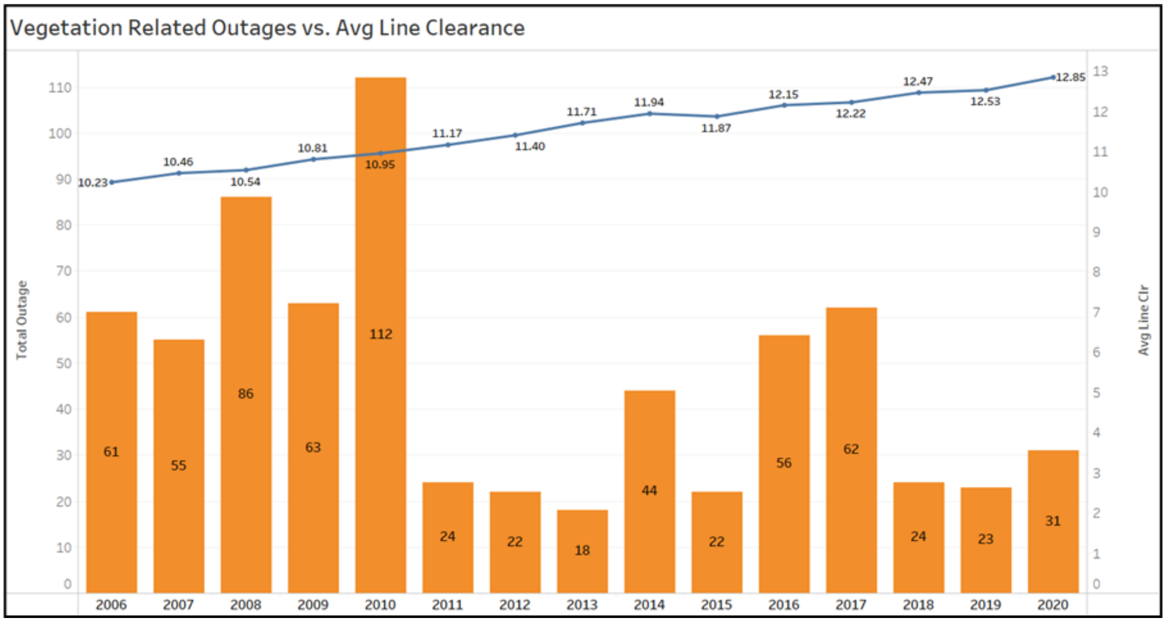


TABLE PG&E-REMEDY-21-23-1:
VEGETATION OUTAGES FOR PRE-ENHANCED VERSUS POST-ENHANCED CLEARANCE

	Inventory Trees Inspected	Vegetation-Related Outages	Outage Rate
Pre-Enhanced Clearance (2006-2016)	4,667,075	554	1.19E-04
Post-Enhanced Clearance (2017-2020)	1,863,658	137	7.35E-05
Difference			-38%

<u>SCE</u>:

In late 2018, consistent with D.17-12-024 which amended GO 95 to increase recommended clearance distances at time of trimming in HFTDs, SCE implemented enhanced clearance programs to achieve greater trimming distances. For purposes of this analysis and considering the time to operationalize enhanced clearances to establish SCE's Grid Resiliency Clearance Distances (at least 12' clearance in HFTD and 6' in non-HFTD) across SCE's service territory, the "pre-enhanced" time frame is considered to be 2015-2019, and "post-enhanced" is focused on 2020 and future years. Outage data in the table/chart represent tree-related events (circuit interruptions) on SCE's distribution system confirmed by SCE field verification as grow-in, blow-in and fall-in events.

This data highlights a decrease in outages associated with vegetation caused events since the advent of SCE's enhanced clearances. Details about the reported events include confirmed tree-related events (Tree Caused Circuit Interruptions – TCCI's) by SCE field verification, and are categorized by Grow-In, Blow-In and Fall-In events.

Approximately 100 TCCI “categories” are reduced to 6 primary categories: Grow-In, Blow-In, Fall-In, Human Caused, No Cause/Not tree related, and Uncategorized. Some events initially reported as a TCCI by SCE’s outage management system could fall into categories that are not indicative of a TCCI once they are investigated and verified in the field. These include Human Caused, No Cause/Not Tree Related, and Uncategorized (the data below does not include these categories). Legacy data was updated to new data collection standards rolled out in 2021. Complete year-to-year outage data is available from 2015 to present and complete enhanced clearance data is available from 2020 to present. This data reflects distribution related events only, as there are no transmission related events of record. Though SCE has tracked TCCIs since 2015, it has only recently made advancements in its work management system that allows SCE to associate specific outage events with the individual/specific trees in its inventory. Outage data was not associated until 2021. Through this joint study, and over the next few years, SCE expects to find more substantial evidence supporting the positive effectiveness of enhanced clearances and the reduction in tree related events. Please see the Time Series of TCCI Events figure and Average Events Pre & Post Enhanced Clearances table showing early indications that implementing enhanced clearances among other programs has decreased the number of events.

FIGURE PG&E-REMEDY-21-23-3:
TIME SERIES OF TCCI EVENTS

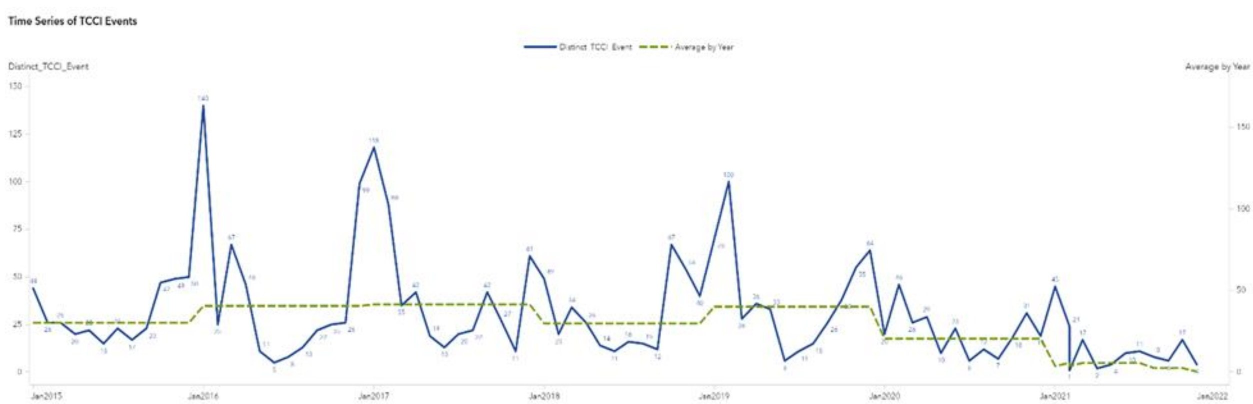


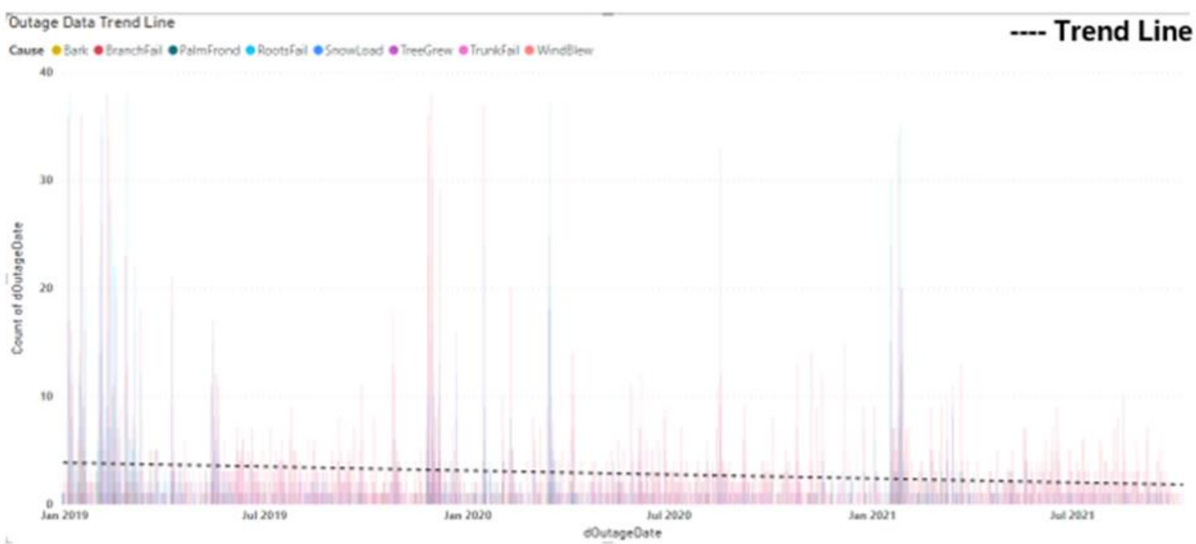
TABLE PG&E-REMEDY-21-23-2:
AVERAGE EVENTS PRE- AND POST-ENHANCED CLEARANCES

Average Events Pre and Post Enhanced Clearances	Pre-Enhanced Clearances	Post Enhanced Clearances	
	2015-2019 Avg TCCIs per Year	2020-2021 Avg TCCIs per Year	Difference
HFTD	148.4	61.5	-59%
Non-HFTD	289.2	136	-53%
All	437.6	197.5	-55%

PG&E:

PG&E’s Enhanced Vegetation Management (EVM) program began in January of 2019 and the image below illustrates the beginning of enhanced clearances toward the end of 2021, or approximately three years of data, but the outages are representative of the entire service territory. The graph shows outage data confirmed as tree-related events and the distinct causes of the outage (Bark, BranchFail, PalmFrond, RootsFail, TreeGrew, WindBlew). Trend line analysis shows a decrease over the three-year period in outage counts associated with these tree-related causes. This is for Distribution conductor only and outage counts were capped at 40 per day to remove outliers in data. (With outliers still represented, the trend analysis also shows a decrease in tree-related causes, but it is more difficult to read in this particular format.) This data is preliminary and the decreases in tree-related causes cannot be attributed solely to enhanced clearances without further examination.

FIGURE PG&E-REMEDY-21-23-4:
3-YEAR OUTAGE DATA TREND LINE



Summary

The early analysis of each IOU demonstrates that after implementing enhanced clearances the number of vegetation-related outages has decreased.

The IOUs will begin 2022 by initiating a process for soliciting proposals from third-party vendors that can assist with achieving and validating the objectives of the study. Now that each utility’s current methods have been reviewed and understood, the process of beginning to standardize data collection and creating a cross-utility database of tree-caused risk events will begin. As preliminary discussions lead to the analysis of vegetation events as the key metric for effectiveness, over the course of this extended study the IOUs may confirm or adjust effectiveness metrics and work towards a more uniform standard for measuring the efficacy of expanded clearances. Part of these discussions included the types of biotic and abiotic factors that can affect the risk of vegetation contact including tree genus/species, tree health, soil composition, storm conditions, Santa Ana winds, etc. The IOUs believe that biotic and abiotic factors can be extracted from existing data sets. Additionally, in partnering with their consultant, the IOUs will begin to examine whether the correlation between enhanced clearances and the lower number of tree-caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor. The joint study will look into whether, and to what extent, other mitigations can be effectively parsed out so as to focus in on the effects of enhanced clearances. To that end, additional data may need to be included in the joint data base (such as the presence of a covered circuit segment) to segregate causal factors.

Each IOU will collect the relevant data identified by Energy Safety for the purposes of this study.

Section 5.8: Resource Allocation Methodology

Utility #: PG&E-21-27

Issue title: Lack of methodology to verify RSE estimates.

Issue description: For capability 41c of the 2021 Maturity Survey, PG&E showed no planned progress by selecting "Utility does not verify RSE estimates" for the years 2020-2023. In order to rely on RSEs to select mitigation initiatives, PG&E must have high confidence that the calculated RSEs are accurate. Moreover, for capability 40a of the 2021 Maturity Survey PG&E selected "Utility has accurate relative understanding of cost and effectiveness to produce a reliable RSE estimate." Without a verification process, the utility cannot guarantee reliability of RSE estimations. PG&E must develop a methodology to assess the accuracy of its RSE estimates.

Remedies required and alternative timeline if applicable: PG&E must provide a detailed RSE verification plan with attainable benchmarks and timeline.

Response to PG&E-21-27:

As described in the Progress Report, PG&E has taken several steps to verify RSE values. Since the Progress Report, those actions have continued and matured, including:

1) PG&E has analyzed real-world data related to specific mitigation programs to verify the effectiveness of those programs (such as system hardening and EVM).

2) A third party technical advising group was hired and has reviewed a significant number of RSE-related materials. As of January 7, 2022, the advising group has: (a) performed a deep-dive review of all RSE calculations used in the 2021 filing; (b) reviewed assumptions associated to dozens of mitigations included in the 2022 WMP; (3) worked with project teams to understand the scope and analytic approaches for each mitigation; and (4) has begun documenting recommendations on how to improve data issues for each mitigation.

3) PG&E has actively participated in joint utility sessions regarding the application of MAVFs and RSEs.

4) PG&E has created an organization tasked with assessing and validating the inputs and outputs to RSE calculations.

Utility #: PG&E-21-28

Issue title: RSE values vary across utilities.

Issue description: Comparatively SCE and SDG&E can, at a base level, verify their calculated RSEs with historical and experimental pilot data. Energy Safety raises a concern that there are stark variances in RSE estimates, sometimes on several orders of magnitude, for the same initiatives calculated by different utilities. For example, PG&E's RSE for covered conductor installation was 4.08,[32] SDG&E's RSE was 76.73,[33] and SCE's RSE was 4,192.[34] These drastic differences reveal that there are significant discrepancies between the utilities' inputs and assumptions, which further support the need for exploration and alignment of these calculations.

Remedies required and alternative timeline if applicable: The utilities[35] must collaborate through a working group facilitated by Energy Safety[36] to develop a more standardized approach to the inputs and assumptions used for RSE calculations. After Energy Safety completes its evaluation of the 2021 WMP Updates, it will provide additional detail on the specifics of this working group.

This working group will focus on addressing the inconsistencies between the utilities' inputs and assumptions, used for their RSE calculations, which will allow for:

1) *Collaboration among utilities;*

2) *Stakeholder and academic expert input; and*

3) *Increased transparency.*

Response to PG&E-21-28:

The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021.

On December 9, 2021, Energy Safety facilitated a public workshop on utility risk spend efficiency (RSE) estimates. Each of the utilities presented the current status of their RSE calculation methodologies, and stakeholders had an opportunity to ask questions of utility representatives as well as RSE experts. RSE experts included Tom Long from

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32 Value from PG&E's Errata (dated March 17, 2021, accessed May 19, 2021: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/naturaldisaster/wildfires/wildfire-mitigation-plan/2021-Wildfire-Safety-Plan-Errata.pdf.

33 Value from Table 12 of SDG&E's 2021 WMP Update submissions under the "Estimated RSE for HFTD Tier 3" column for "Covered Conductor Installation."

34 Value from Table 12 of SCE's 2021 WMP Update submissions under the "Estimated RSE for HFTD Tier 3" column for "Covered Conductor Installation."

35 Here "utilities" refers to PG&E, SDG&E, and SCE.

36 The WSD transitioned to the Energy Safety on July 1, 2021.

The Utility Reform Network (TURN), Fred Hanes, senior utilities engineer from the California Public Utilities Commission (CPUC), and Joseph Mitchell from Mussey Grade Road Alliance (MGRA). The participants discussed RSE calculation methodology best practices and how RSE estimates inform wildfire risk-based decision-making.

At the conclusion of the workshop, Energy Safety requested that the utilities submit reports providing a detailed description on their RSE calculation methodology. Each utility developed a report on their RSE calculation methodology, RSE estimate verification process, and RSE estimate initiative-selection process. These reports were submitted on December 17, 2021.

The utilities look forward to continuing to work with Energy Safety and other stakeholders in pursuit of utility collaboration, expert input, and increased transparency on RSE assumptions, inputs, and calculations.